Analysis of Welltest BRI-GT-02

2 October 2015

G1177

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Summary

Well BRI-GT-02 was production tested from 19-21/09/2015 by a multi-rate test with a short build-up after each flow period, followed by a shut-in period of 22 hours. The ESP generated production rates varied between 220 and 380 m3/hr. Cumulative water produced was about 5860 m^3.

Following are the main conclusions:

- Average reservoir permeability is about 170 mD assuming that the whole net sand contributes to flow. This is at the low end of the permeability envelope estimated from core data (150 – 300 – 1500mD).
- The skin at 376 m3/hr is + 1.3, mostly a rate-dependent skin due to friction in the tubing. At low rates the skin is negative at -0.46.
- A possible single flow barrier is evaluated at a distance of about 900 m from the wellbore.
- Static reservoir pressure at 2100 m tvBRT is 213.2 bara.
- Reservoir temperature is ~ 80 ºC.
- The transient flow capacity (PI) after 44 hours flow is 13 m^3/hr/bar at the highest flowrate of 376 m3/hr. Without friction losses in the vertical conduit the PI would have been 15.8 m^3/hr/bar after 44 hrs.
- The injectivity (II) declined during the injection of a volume of 626 m3 water from 13 m3/hr/bar (initially) to 6.6 m3/hr/bar (final) due to an increasing skin from 1.0 to 12.3. Up to 60% of this increase may be caused by the forming of a cold-water bank around the well.

Results test interpretation and analysis		
Permeability thickness kh	27.7	Dm (Darcy-meter)
Assumed net h	160	m
Permeability kh	170	mD
Skin S at 376 m3/hr*	1.3	
Skin at 0 m3/hr	-0.4	
Possible flow barrier at	900	m
Productivity Index (P.I.) (44hrs) at zero rate*	15.8	m3/hr/bar
Productivity Index (P.I.) (44hrs) at 376 m3/hr	13	m3/hr/bar

*) Skin is rate dependent due to friction in flow conduit.

Resultaten van de puttest

Gegevens voor test interpretatie		Waarde	Dimensie
Naam van de put		BRI-GT-02	
Top aquifer		2276.5	m (langs boorgat)
“		2026.5	en m (TVD)
Basis aquifer		2553.5	m (langs boorgat)
“		2204	en m (TVD)
Netto dikte Aquifer		160	m (TVD)
Netto/bruto aquifer		90	%
Gemiddelde porositeit aquifer		20	%
Zoutgehalte formatiewater van sample		115 E3	PPM
Verwachte max. temperatuur geproduceerde water[1]		80	ºC
Casing 24“		224	m tv
Casing 13 3/8”		1241	m tv
Casing 9 5/8”		2030	m tv
Diameter boorgat bij aquifer		8.5	Inch
Top productie-interval/filter (6 5/8 x 7”)[2]		2283	m (langs boorgat)
“		2031	en m (TVD)
Basis productie-interval/filter (6 5/8 x 7”)		2560	m (langs boorgat)
“		2207	en m (TVD)
Weerstand over screens		0	bar
Locatie pomp		737	m (tv en langs boorgat)
Locatie meetsonde voor druk		747	m (tv en langs boorgat)
Clean up gegevens			
Pompdruk		44.6	bar
Debiet vs. tijd		389	m3/uur
Duur		4.0	uur
Meetreeksen Puttest[4]		Eind ESP druk, bar	Eind Debiet, m3/uur
Flow 0		69.6	0
Flow 1		58.3	222
Flow 2		51.7	305
Flow 3		45.1	376
Uitkomsten test interpretatie en analyses			
Skin		-0.4	
Rate dependent skin D		1.26 E-05	$1/(m3/hr)^2$
H		160	m
kH		27.7	D*m
PI (transient 44 hrs)		13	m^3/hr/bar
Deviatie			
Diepte langs boorgat	Diepte m tv	East	North
0	0	70431.5	432182.5
2276.5	2026.5	70317	431586
Mid reservoir 2415	2115	70295	431478
2553.5	2204	70277	431371

1 Deze temperatuur wordt als gemiddelde aquifer temperatuur beschouwd

Contents

1 Introduction

Well BRI-GT-02 was production tested from 19-09-2015 15:24 to 20-09 12:29, followed by a shut-in period of 22 hours. ESP generated production rates varied between 220 and 376 m3/hr. Cumulative water produced was 5860 m^3.
The pressure and temperature data were recorded by the ESP gauge at 747 m tvBRT.

The well was produced from the Main Bunt-sandstone, 2026.5 – 2204 m tvBRT (2276 – 2554 m ahBRT), covered by screens.

The correction formula, as determined from the ESP data in combination with the downhole gauge during the test of well GT01 in August 2015, was used to correct the ESP pressures to a datum depth of 2100 mtv.

2 Reservoir and Rate data

The porosity of the Main Bunt-sandstone has been estimated at 20%., as the sand quality is better than in GT01. The same net/gross ratio of 90% has been used as in GT01, resulting in a net sand thickness of 160 m.

The wellbore radius Rw has been set to the bit size of 8.5", or 0. 354 ft.
In view of the deviation of the well with an average angle of about 50 degrees through the reservoir, the wellbore radius was adjusted to $Rw*\sqrt{\{(1+1/\cos\alpha^2)/2\}}$ = 0.45 ft, for the analysis with a vertical well model.
The reservoir temperature is estimated at 80 C, the maximum extrapolated gauge temperature.
The same water salinity of 155 gr/ltr NaCl (14%) and water density of 1102 kg/m3 at 15 ºC as determined from the observed gradient in well GT01 has been used.
Standard tables show for this salinity a water compressibility of 2.4 E-6 psi^{-1}, and a water viscosity of 0.47 cP. The pore compressibility is assumed to be 3E-6 psi^{-1}. The porosity and total compressibility (Cw + Cf) may have to be changed after the interference test results with the first well.

The next table lists the used rate sequence during the production test.

Hours since start Test''	Delta time, hours	Flow Rate, m3/hr
1.088	1.088	215
2.085	0.997	319
3.055	0.970	342
4.094	1.039	389
5.077	0.983	0
8.104	3.027	226
9.086	0.982	0
10.205	1.164	279
12.103	1.898	310
13.120	1.017	**0**
21.084	7.964	376
44.183	23.099	0

'') On 19/09/2015 15:24:47

3 Correction for water column cooling on gauge data

From the test of BRI-GT01 last august, the following correction for the ESP pressures has been derived:

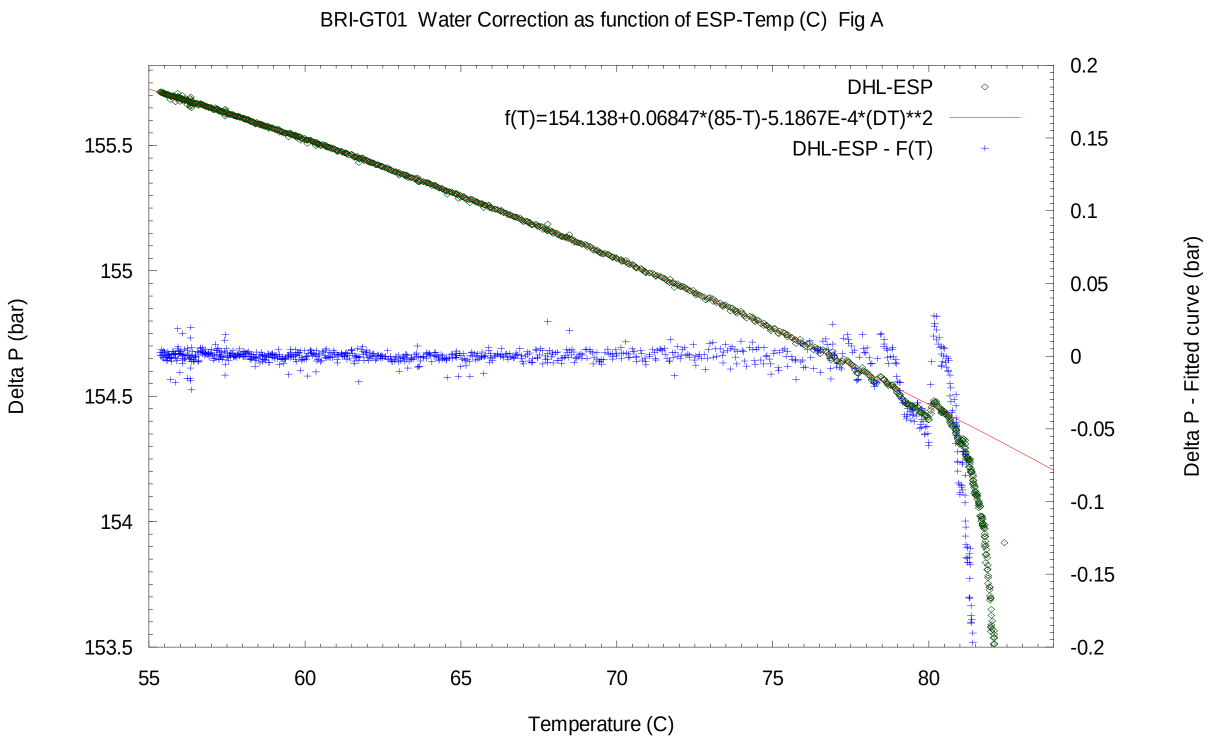
The pressures of the downhole gauge in GT01 have been correlated with the ESP pressures as function of the ESP temperature in Fig-A. The resulting correction formula, only matching on the EST temperatures below 79 ºC, is:

$\Delta P = CDC*L*[1062.06+0.4718*\Delta T -0.003574*\Delta T^2]$,

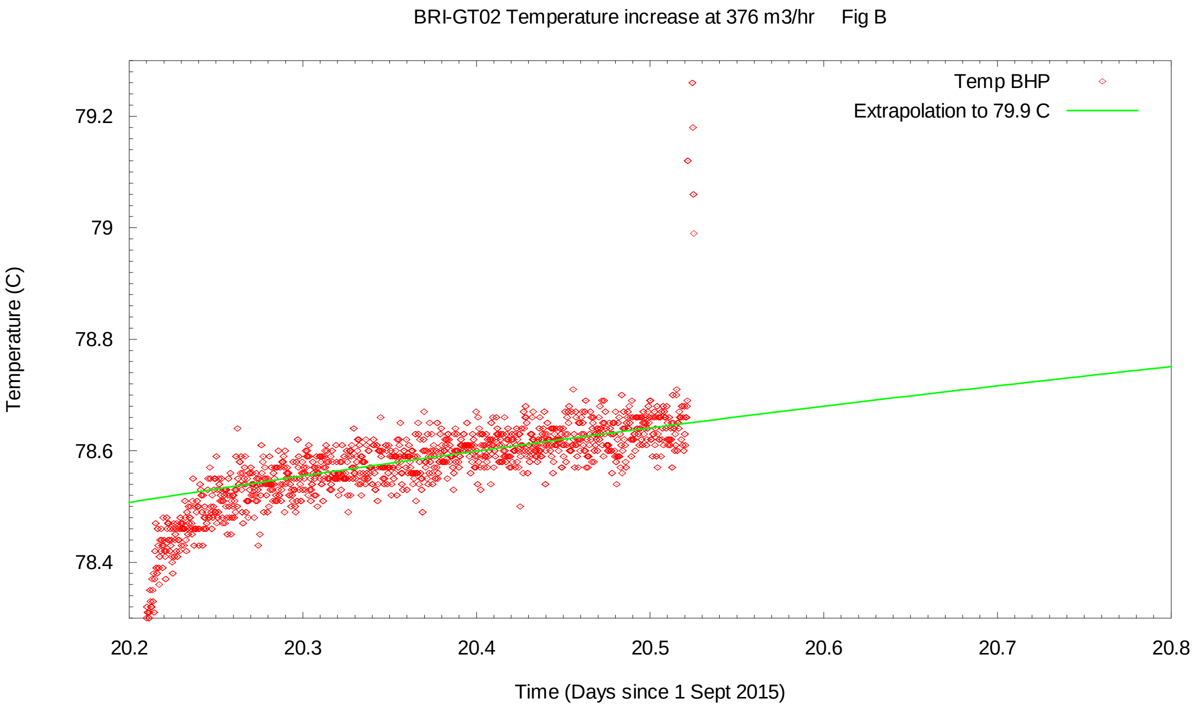
With ΔP the pressure correction, CDC a constant [CDC= 9.8063E-5 if pressure in bar and L in meters], L the vertical depth difference between the deep gauge and ESP depth (1481 m), and ΔT the difference between the maximum (84 ºC) and current ESP temperature in ºC.

The green points are the pressure differences between BHP and ESP, with the fitted red curve through those points. The blue points are the difference between the green dots and the fitted curve on the right-hand scale. It is clear that the early build-up data with an ESP temperature above 79 ºC can not be used for the model matching as they are clearly disturbed by wellbore effects like gas bubbling upwards, cold water moving downwards and the latent heat of the ESP motor, influencing the recorded temperature just after shut-in.

Above equation has been used to correct the ESP pressures in GT02 down to the datum depth of 2100 mtv, using a maximum reservoir temperature of 80 ºC; L is thus 2100 – 747 = 1353 m.



The maximum expected future water temperature in GT-02 of 79.9 ºC at the ESP depth is obtained by extrapolation of the recorded temperature during the 8 hours long flow period at the highest rate of 376 m3/hr, Fig B. Note the peak in the temperature just after shut-in. This is caused by the latent motor heat of the ESP, heating the surrounding water after the cooling of the flowing water has stopped.



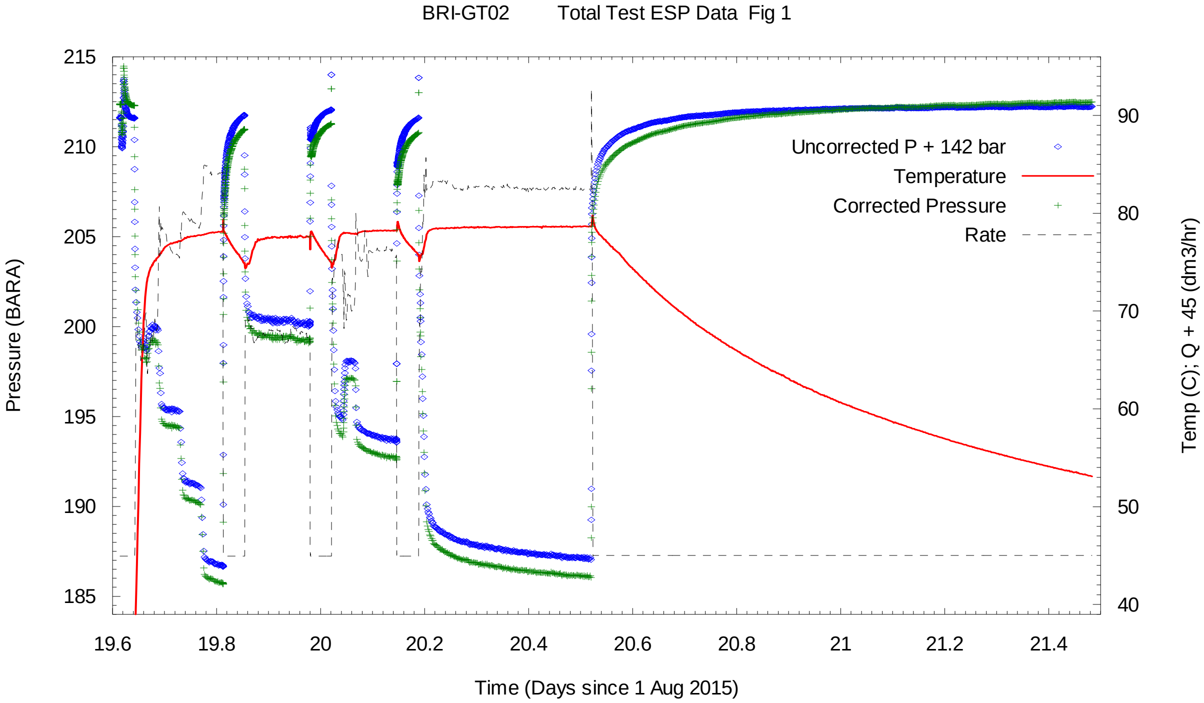
4 Pressure recordings

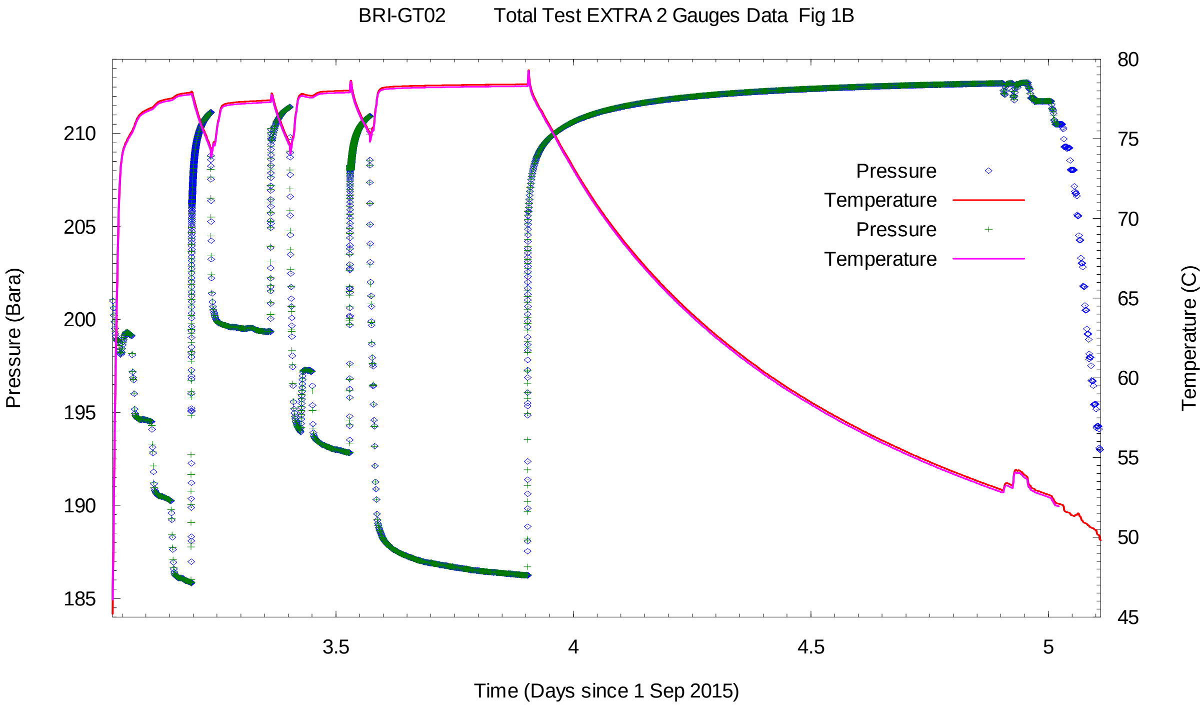
Fig-01 shows the original ESP data (plus a constant 142 bar) together with the pressures corrected for the 1353 m water column down to the datum depth of 2100 m tvBRT.

The black dotted line represents the flow rates during the test in Deca m3/hr with 45 added.

The effect of the correction is clearly visible in the final build-up.

Fig-01B presents the corrected pressures of the two extra gauges placed just below the ESP.
As the data of both gauges are practically identical, only the bottom of these two gauges has been used for analysis, Figures 2B and 3B in chapter 6.


BRI-GT02 Total Test ESP Data Fig 1
Pressure (BARA)
Temp (C); Q + 45 (dm3/hr)
Time (Days since 1 Aug 2015)
Uncorrected P + 142 bar
Temperature
Corrected Pressure
Rate
215
210
205
200
195
190
185
90
80
70
60
50
40
19.6
19.8
20
20.2
20.4
20.6
20.8
21
21.2
21.4


BRI-GT02 Total Test EXTRA 2 Gauges Data Fig 1B
Pressure (Bara)
Temperature (C)
Time (Days since 1 Sep 2015)
Pressure
Temperature
Pressure
Temperature
210
205
200
195
190
185
80
75
70
65
60
55
50
45
3.5
4
4.5
5

5 Analysis method

The analysis is carried out by the match of the most appropriate analytical well/reservoir model with the total test history. In this way, no approximations have to be used, as for the model response the flow equations are solved with great precision for the reported flow rates. It should be noted that each pressure point measured in a well depends on the total previous rate history of that well, both in the real reservoir as in the analytical model. Analysis of only one rate period can thus give only an approximation of the real reservoir/well parameters.

As no model for a deviated well is available, a vertical well model has been used, based on the assumption that the flow in the reservoir at some distance from the well will be horizontal, as the vertical permeability is normally lower than the horizontal one in sandstone. The matched-model response for short times can be expected to deviate somewhat from the observed pressures. But these early build-up pressures are also expected to be influenced by cold water, falling down from the annulus above the pump, gas bubbling upwards and expanding, and possibly by water hammer and (ESP Data) by the latent motor heat.

6 Analysis of corrected ESP pressure data

Fig-02 presents the Horner plot plus derivative of the final, main, build-up for the corrected ESP data.
This plot clearly shows the radial-flow straight Horner line.
The slight curvature of the derivative at the very end is likely a sealing flow barrier at about 900 m from the well.
The slope of the Horner line results in a permeability of the 160 m net sand of 173 mD.
The skin at the final flowrate of 376 m3/hr is +1.3.
The early wellbore effects last only 4.5 minutes and are influenced by the temperature effects of the hot motor, cold water fall-down from the annulus and possible some free gas expansion.

Fig-03 presents the match versus linear time, showing the good match with the final flow period of nearly 8 hours. The earlier, lower flowrates are not matched that well. Matching in turn on the three main test rates result in Skin values of respectively 0.15, 0.83 and 1.29. Plotting these versus the squared rates resulted in Fig-C, indicating a mechanical skin at zero rate of -0.46 and a rate dependent skin of 1.24E-05 $\{d/m^3)^2$.
The reservoir pressure is 213.2 bara at 2100 mtv.

PI is 13 m3/hr/bar after 44 hrs at the highest rate of 376 m3/hr. Without the friction in the vertical conduit, the (transient) PI would be 15.8 m3/hr/bar.

Figures 2 and 3 show a sinusoid in the ESP pressures with a period of about 2 hours and an amplitude of 0.02 bar.

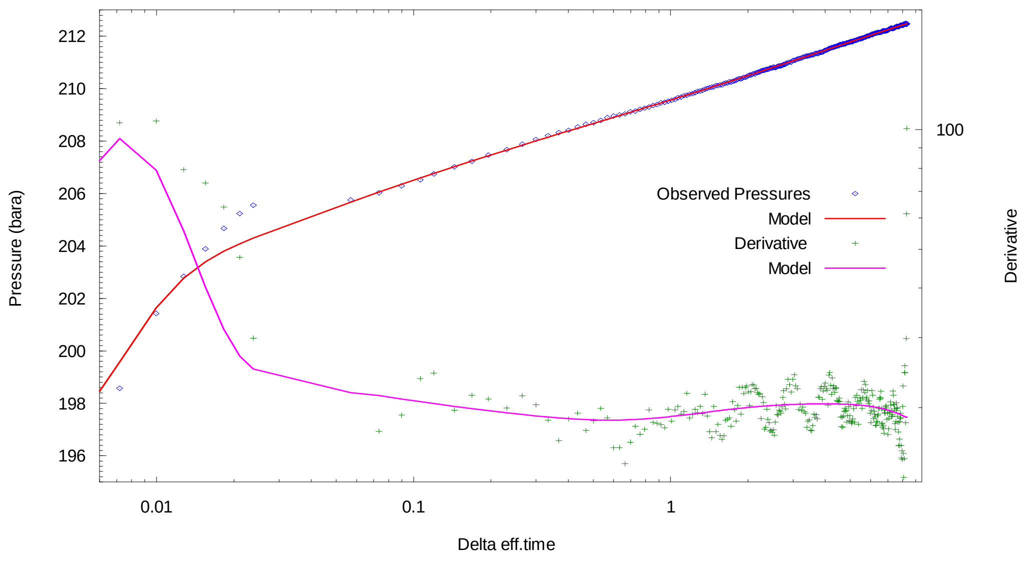
The slight dip of the derivative at 0.7 hrs in Fig02 may be caused by wellbore effects, but has also been matched with a two-layer system, with the better layer of 96 m thickness having a permeability of 260 mD and skin 1.05 and the other 64 m a permeability of 43 mD and skin 4.5. The vertical permeability is high at 47 mD.
Apart from a flowmeter survey, there is no way to decide if this is a realistic reservoir effect or if it is caused by the deviation, or just a wellbore effect. For the circulation project is has absolutely no consequences, as the reservoir behaves as a single layer within 3 hours.
The analysis of the more accurate gauge with a much higher sampling frequency of one point every 2 seconds is presented in the figures 2B and 3B:

The model is the same two-layer model with only slightly different properties:
The average permeability is 170 mD, average skin 1.3. The best layer is now 88 m thick with a permeability k1 of 278 mD and S1 of 0.87. The poorer layer is 72 m with 38 mD, S2 of 5.2 with a vertical permeability of 49 mD.
The strange sinusoid is not present on these data and is thus an artefact of the ESP gauge.

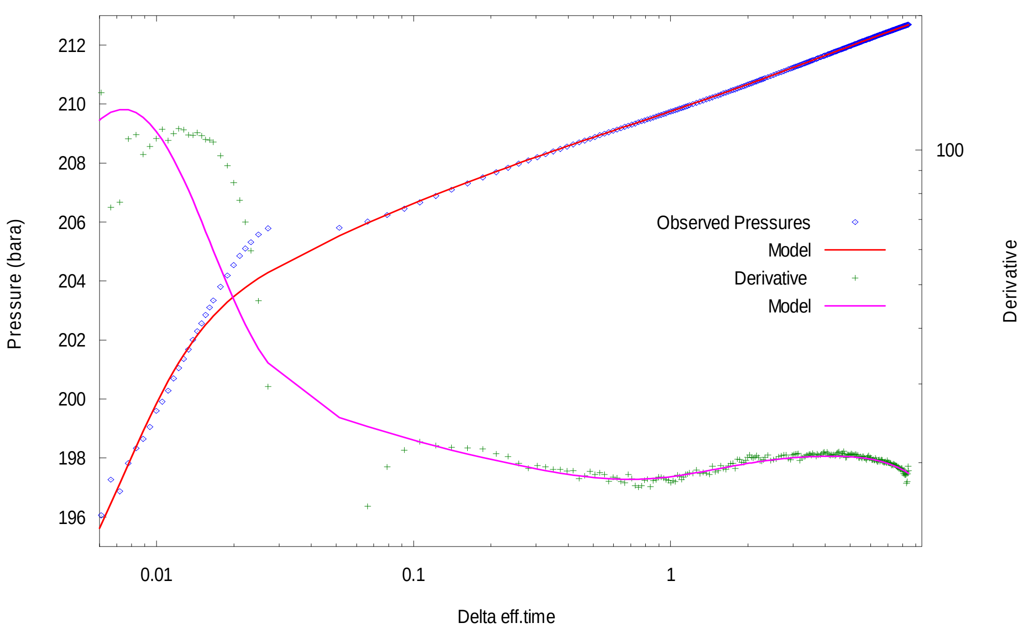
The skin plot, Fig-C, has been remade with the skin data for the earlier rates with this new model, respectively 1.30, 0.87 and 0.22, resulting in a mechanical skin of -0.4 and a rate dependent skin of 1.2E-05 $\{d/m^3\}^2$.

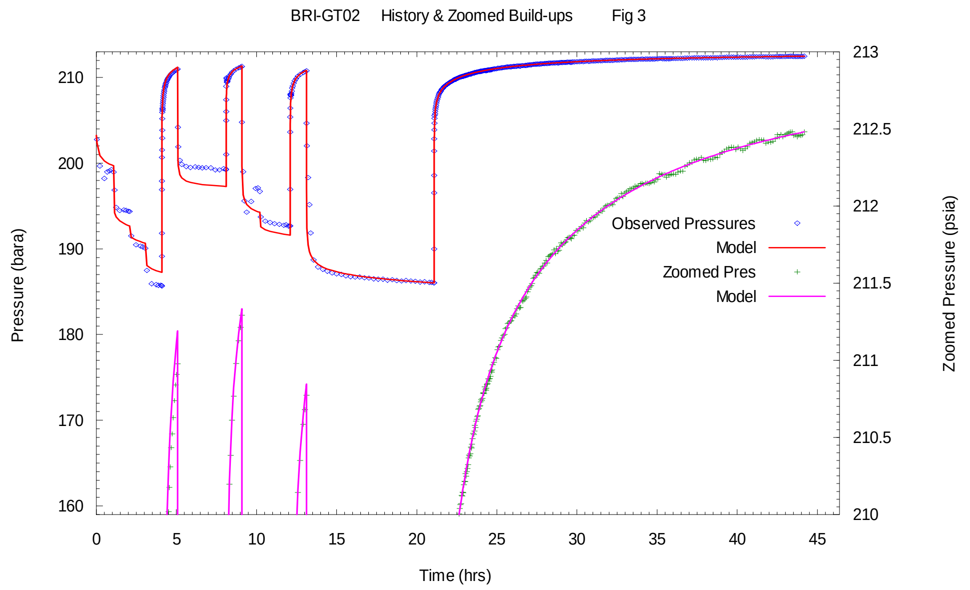
The two-layer effect does look like a realistic layering of the reservoir in Fig-2B.

BRI-GT02 Horner Plot & Derivative, Main BU Fig 2

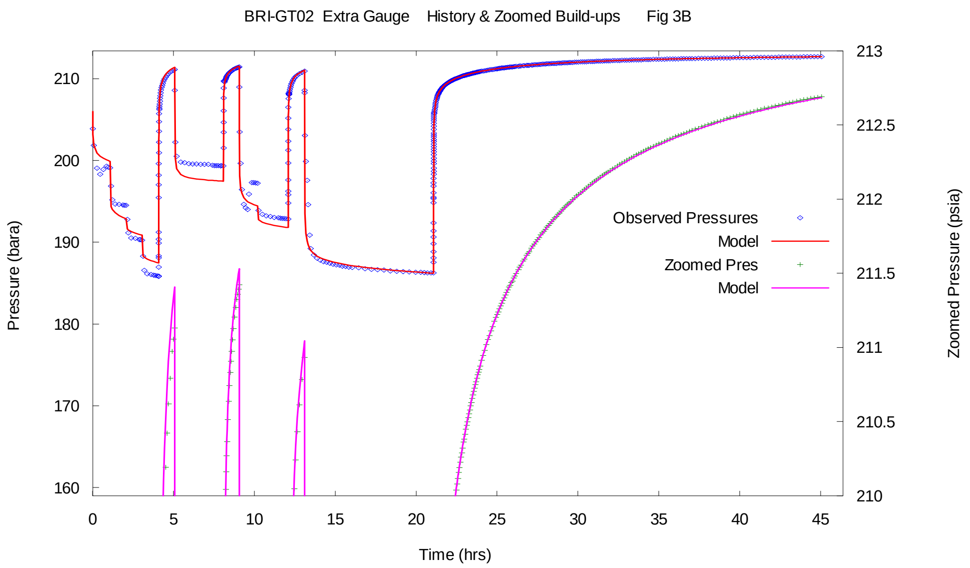


BRI-GT02 Extra Gauge Horner Plot & Derivative, Main BU Fig 2B

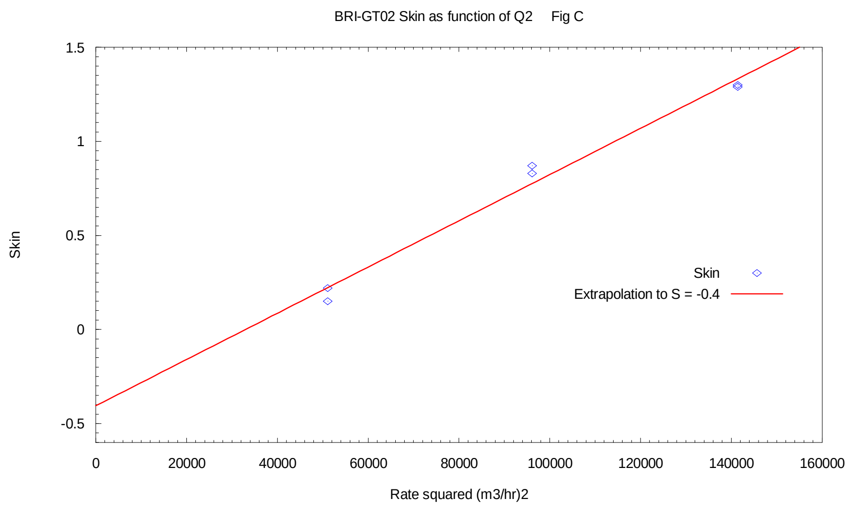




BRI-GT02 History & Zoomed Build-ups Fig 3
Pressure (bara)
Zoomed Pressure (psia)
Time (hrs)
Observed Pressures
Model
Zoomed Pres
Model



BRI-GT02 Extra Gauge History & Zoomed Build-ups Fig 3B
Pressure (bara)
Zoomed Pressure (psia)
Time (hrs)
Observed Pressures
Model
Zoomed Pres
Model



BRI-GT02 Skin as function of Q2 Fig C
Skin
Rate squared (m3/hr)2
Skin
Extrapolation to S = -0.4

7 Analysis of injection data

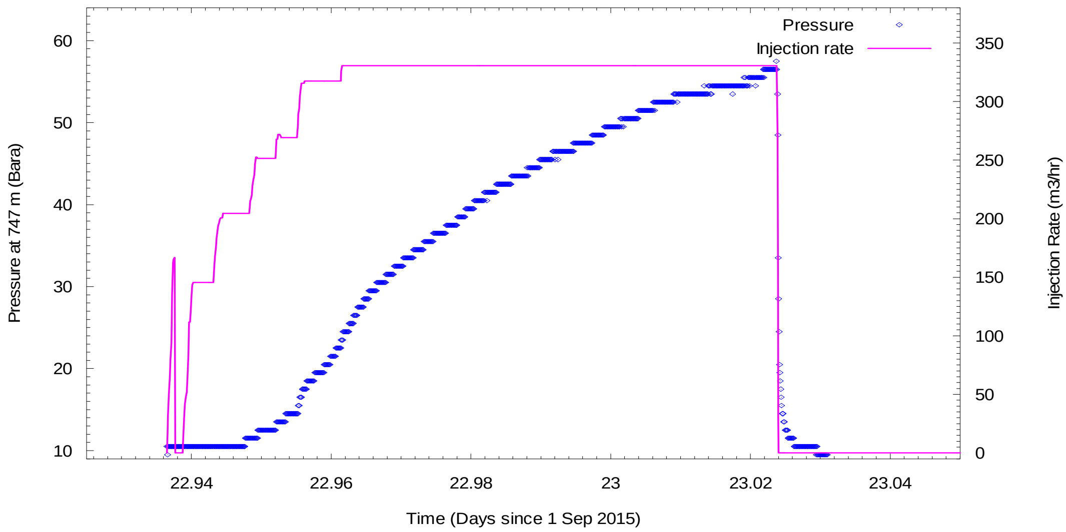
From 22-09-2015 22:28 to 23-09-2015 00:34, 626 m^3 water was injected back into the well at a final rate of 330 m3/hr.

During the initial injection the surface pressure remained zero (atmospheric). This is caused by the weight of the salt water in the well with a higher weight than that of the hydrological water column determining the reservoir pressure. From the static ESP pressure of 70 bara at 747 mtv follows a free water level in the well of [747 - 70 / (1.1 * 0.098067)] = 98 m at an average water temperature of 20C.

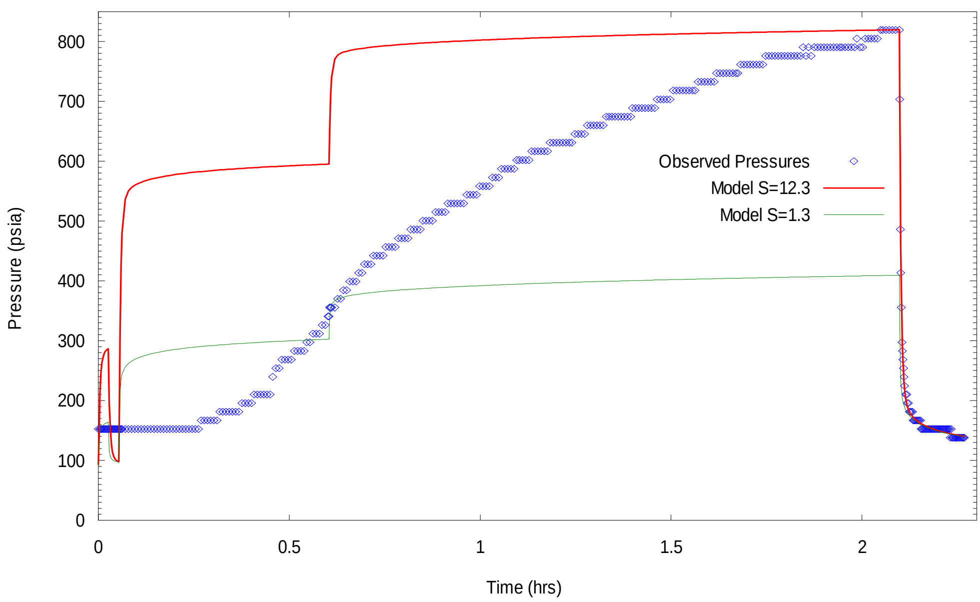
Injecting water at 35C this 98 m is equivalent with an overpressure at reservoir level of 1.093 * 0.098067 * 98 = 10.5 bar.

Consequently this extra pressure has been added to all measured surface pressures during injection, resulting in the injection test data plot of Fig-04 below.

BRI-GT02 Injection Test Surface Data Fig 4



BRI-GT02 Matched Injection Test Fig 5



This injection history has been matched with the same homogeneous model as used for the production test data, with a k of 170 mD and starting with a skin of 1.3, the green line in FIG-05.
During the main injection period the skin is continuously increasing with a final skin of 12.3.

The good match of the fall-off confirms the production data analysis (same k*h).

A total of 626 m3 cold water was injected, forming a cold water area around the well with a radius of 2.5 m. In practice, the radius with a cold water viscosity is half this distance (some 1.25 m) due to heat exchange with the reservoir sand. Using a composite-radial model to match the final flow and fall-off with a cold water viscosity of 0.65 cP (T of 60°C) in this inner circle did give the same match, but with a damage skin of 8.1 instead of 12.3. Some 30 % of the skin increase may thus be caused by the increase in water viscosity around the wellbore. The remaining 70 % of total skin is seemingly due to something plugging-up the open screens.
Even if the water in this cold-water bank is 40 °C the skin is a high 5.4, and at 20°C still 2.9, to be compared with 1.0 (total skin at the injection rate of 330 m3/hr).

The final Injectivity Index is only 6.6 m3/hr/bar.

8 Conclusions

The main conclusion is that the well-defined radial-flow period in the Horner plot of the main build-up makes the determination of the average permeability rather straightforward, within the accuracy of the flow rates. There is not much doubt about the k*h of 170*160 mD.m.

The evaluation with the two-layer model gives an indication of the layering in this reservoir, but has no influence on the cycling project. The analysed high vertical permeability for this two layer model indicates that there are many thinner layers of higher and lower k and S, distributed over the reservoir height. The variation in skin between the good and poor layers is probably caused by the acid wash, with the acid preferentially entering the high permeability layers. Without this effect no layering would have been observed on the derivative of the build-up.

The overall negative mechanical skin indicates the success of the acid wash before the test and is in great contrast to the test of the first well without such an acid wash.

The presence of a flow barrier at about 900 m from the wellbore is deduced from the slight dip in derivative at the end of the build-up, making this distance not too accurate.

The injection test shows a continuous increase in skin from an initial value of 1.0 (at 330 m3/hr) to 12.3 after an injection of 626 m3 water. Up to 60% of this increase may be caused by the forming of a cold-water bank around the well with a higher water viscosity, as the injected water was reported to have a temperature of only 21 °C. However in view of the rather low amount of injected cold water this effect is probably much smaller than 60 %.
The rest is anyhow caused by pugging. (fines/corrosion products/grease?)