Analysis of Welltest BRI-GT-01

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Summary

Well BRI-GT-01 was production tested from 12-15/08/2015 by a multi-rate test with a short build-up after each flow period, followed by a shut-in period of 24 hours. The ESP generated production rates varied between 167 and 324 m3/hr. Cumulative water produced was about 4600 m^3.
The production test was followed by a 7 hours injectivity test on 15/08/2015, the results of which are also included in this report.

Following are the main conclusions:

- Average reservoir permeability is about 120 mD assuming that the whole net sand contributes to flow.
- The reservoir shows a two-layer effect with 27% not producing (S2 set to infinite) and 73% with a skin (S1) of 2.8. This skin appears to be increasing during the test with an initial value of 0.3.
- The vertical permeability is about 1.4 mD.
- A possible single flow barrier is evaluated at a distance of about 800 m from the wellbore.
- Static reservoir pressure at 2200 m tvBRT is 223.5 bara.
- Reservoir temperature is ~ 84 ºC.
- The correction for the changing temperature of the water column between the ESP and top reservoir appears to be working reasonably well for the build-up data one hour after shut-in.
- The transient flow capacity (PI) after 55 hours flow is 6.8 m3/hr/bar, declining from 8.4 during the clean-up; removal of the skin of both layers to a value of -0.5 will increase the 55 hrs PI to 13.6
- The (still decreasing) transient injectivity (II) at the end of the injection test is only 3.2 m3/hr/bar, caused by an effective skin of 28 for both layers, apparently caused by a continuously further plugging of the screens.

Resultaten van de puttest

Gegevens voor test interpretatie	Waarde	Dimensie
Naam van de put	BRI-GT-01	
Top aquifer	2779	m (langs boorgat)
“	2172	en m (TVD)
Basis aquifer	3089	m (langs boorgat)
“	2376	en m (TVD)
Netto dikte Aquifer	183	m (TVD)
Netto/bruto aquifer	90	%
Gemiddelde porositeit aquifer	18	%
Zoutgehalte formatiewater uit gradient	155. / 140E3	Gr/ltr NaCl / PPM
Zoutgehalte formatiewater van sample	115E3	PPM
Verwachte max. temperatuur geproduceerde water[1]	84	ºC
Casing 24“	226	m tv
Casing 13 3/8”	1236	m tv
Casing 9 5/8”	2172	m tv
Diameter boorgat bij aquifer	8.5	Inch
Top productie-interval/filter (6 5/8 x 7”)[2]	2779	m (langs boorgat)
“	2172	en m (TVD)
Basis productie-interval/filter (6 5/8 x 7”)	3057	m (langs boorgat)
“	2355	en m (TVD)
Locatie pomp	610	m (tv en langs boorgat)
Locatie meetsonde voor druk	619	m (tv en langs boorgat)
Locatie diepe wireline gauge	2669	m (langs boorgat)
“	2100	m tv
Clean up gegevens		
Pompdruk	282	psi
Debiet vs. tijd	258	m3/uur
Duur	1.8	uur
Meetreeksen Puttest[4]	Eind ESP druk, bar	Eind Debiet, m3/uur
Flow 0	56	0
Flow 1	39	167
Flow 2	30	240
Flow 3	14.5	315
Uitkomsten test interpretatie en analyses		
Skin	7,5	
H	183	m
kH	120*183	mD*m
PI (transient 55 hrs)	6.8	m^3/hr/bar
Deviatie		

Diepte langs boorgat	Diepte m tv	East	North
0	0	70428	432179
2779	2172	68998	432403
Mid reservoir 2935	2274	68881	432422
3089	2376	68768	432444

1 Deze temperatuur wordt als gemiddelde aquifer temperatuur beschouwd

2 Geen meting van weerstand over filter

Results test interpretation and analysis		
Permeability thickness kh	22	Dm (Darcy-meter)
Assumed net h	183	m
Permeability k_h	120	mD
Permeability k_v	1.4	mD
Average skin S*	7.5	
Upper 133 m has skin S1	2.8	
Lower 50 m has skin S2	Infinite	
Possible flow barrier at	800	m
Initial Productivity Index (P.I.) (55hrs)	8.4	m^3/hr/bar
Final Productivity Index (P.I.) (55hrs)	6.8	m^3/hr/bar
Ideal PI, S of -0.5 (55 hrs)	13.6	m^3/hr/bar
Final Injectivity Index (I.I.)	3.2	m^3/hr/bar

*) Skin along whole reservoir depth (183 m) to give same productivity.

Contents

1 Introduction

Well BRI-GT-01 was production tested from 12-08-2015 5:52 to 13-08 13:29, followed by a shut-in period of 24 hours. ESP generated production rates varied between 167 and 324 m3/hr. Cumulative water produced was 4600 m^3.
The pressure and temperature data were recorded both by the ESP gauge and a high-accuracy gauge on wireline at 2100 m tvBRT.

The ESP pressure sensor is at 619 m tvBRT. The well was produced from the Main Bunt-sandstone, 2172 – 2376 m tvBRT (2779 – 3089 m ahBRT), covered partially by screens from a depth of 2172 to 2355 m tvBRT. The bottom 21 m (tv) of the reservoir was covered by an uncemented and unperforated blind pipe.

The correction formula, as determined from the ESP data in combination with the downhole gauge, was used to correct the deep gauge pressures down to a datum depth of 2200 m tvBRT. Also the ESP pressures were corrected to this datum depth.

After the production test, from 15-08-2015 19:50 to 16-08 2:50, a total of 677 m3 water was injected back into the well. The 4 hours of injection rates and surface (choke) pressures have been matched with the same model as matched on the production test.

2 Reservoir and Rate data

The porosity of the Main Bunt-sandstone has been estimated at 18%., the middle value of estimates ranging from 15 to 21.6%. Net reservoir thickness is roughly estimated from the gamma ray log as a total of 90% of the 204 m, or some 183 m (600 ft).

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 49 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 84 C, the maximum extrapolated gauge temperature.
The water salinity is obtained from the observed pressure gradient at 81 ºC of 0.10437 bar/m. This has to be multiplied by 10197.16 to convert into a water density of 1064.3 kg/m3. This is consistent with a water salinity of 155 gr/ltr NaCl (14%) and a density of 1102 kg/m3 at 15 ºC.
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 with the next well.

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

Hours since start Test’’	Delta time, hours	Cumulative prod., m3	Flow Rate, m3/hr
1.2196	1.220	250.6	205.5
1.8723	0.653	418.8	257.7
11.001	9.138	418.8	0
12.263	1.253	760.9	270.7
13.137	0.874	1044.2	324.3
14.193	1.056	1044.2	0

14.347	0.154	1071.6	178.3
15.101	0.754	1071.6	0
19.181	4.080	1752.1	166.8
20.145	0.964	1752.1	0
20.734	0.589	1869.0	198.5
24.113	3.379	2683.7	241.1
25.529	1.416	2683.7	0
31.601	6.072	4600.0	315.6
55.281	23.68	4600	0

‘’) On 12/08/2015 5:52:48

3 Correction for water column cooling on gauge data

The pressures of the downhole gauge were 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:

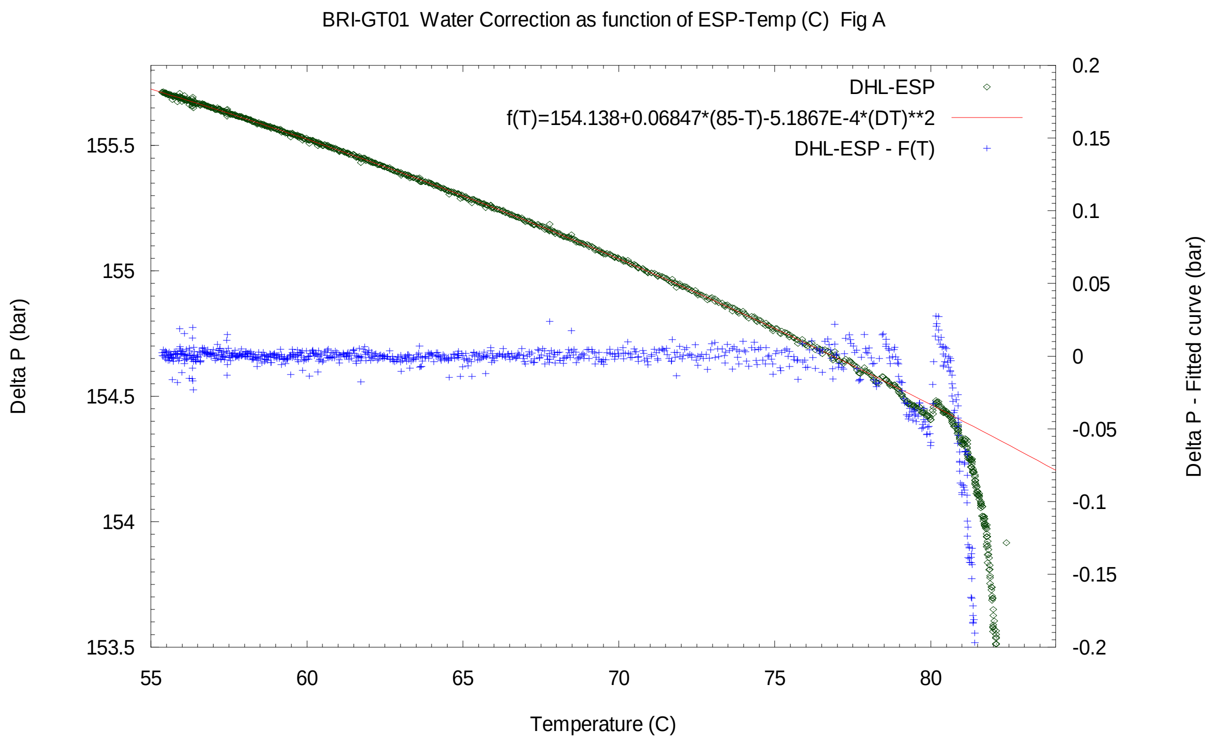
$\Delta P=CDC*L*[1062.06+0.4718*\Delta T-0.003574*\Delta T^2]$,

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 datum and ESP depth (1481 m), and ΔT the difference between the maximum and current ESP temperature in ºC.

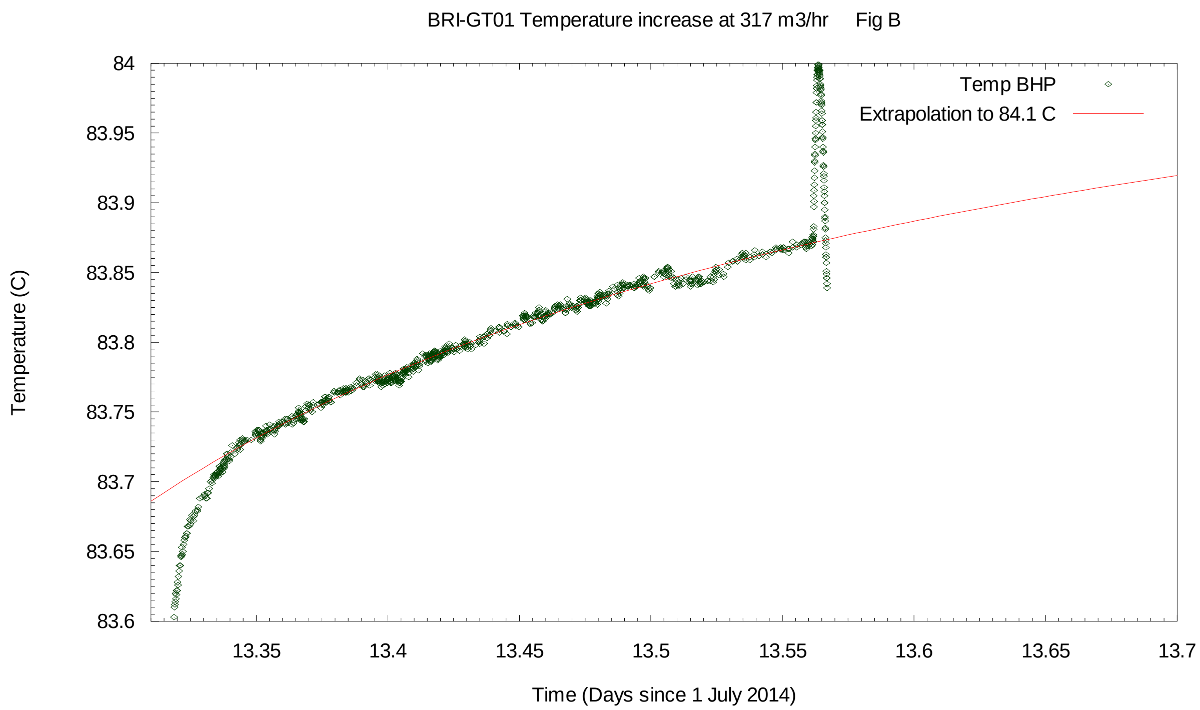
As maximum temperature 84 ºC was used, based on the extrapolation of the downhole temperature, Fig-B.

This formula corrects thus from ESP to BHP depth. It has also been used for the extrapolation from BHP to datum depth.

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.
No gauge movement is seen on the blue dots at the large scale, leading to the conclusion that no wireline shrinkage occurred during the build-up



The maximum expected future water temperature at the gauge depth of 84.1 ºC is obtained by extrapolation of the recorded temperature during the 6 hours long flow period at the highest rate of 317 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.

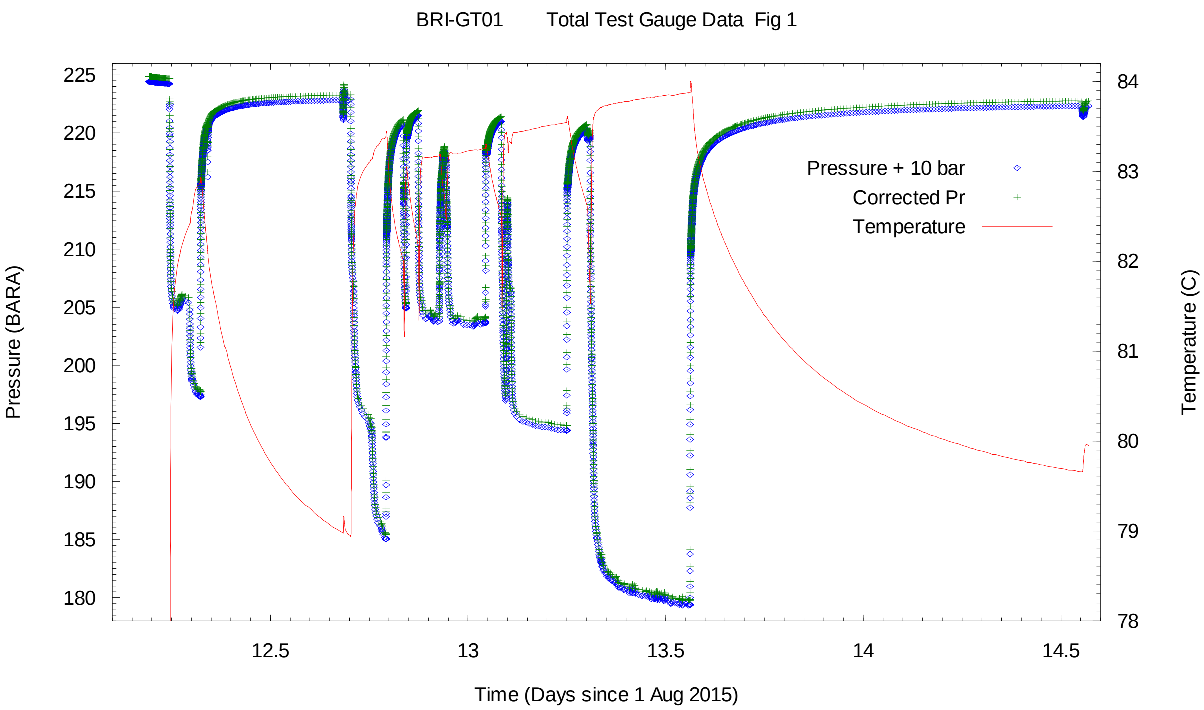


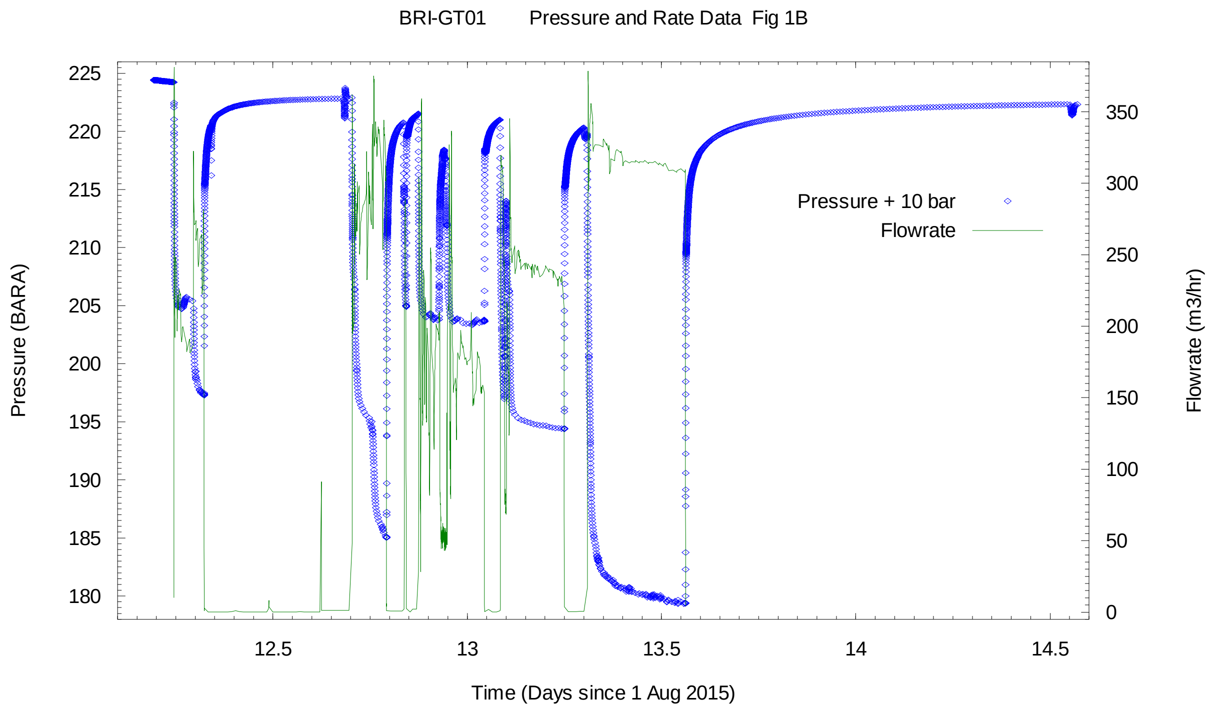
4 Pressure recordings

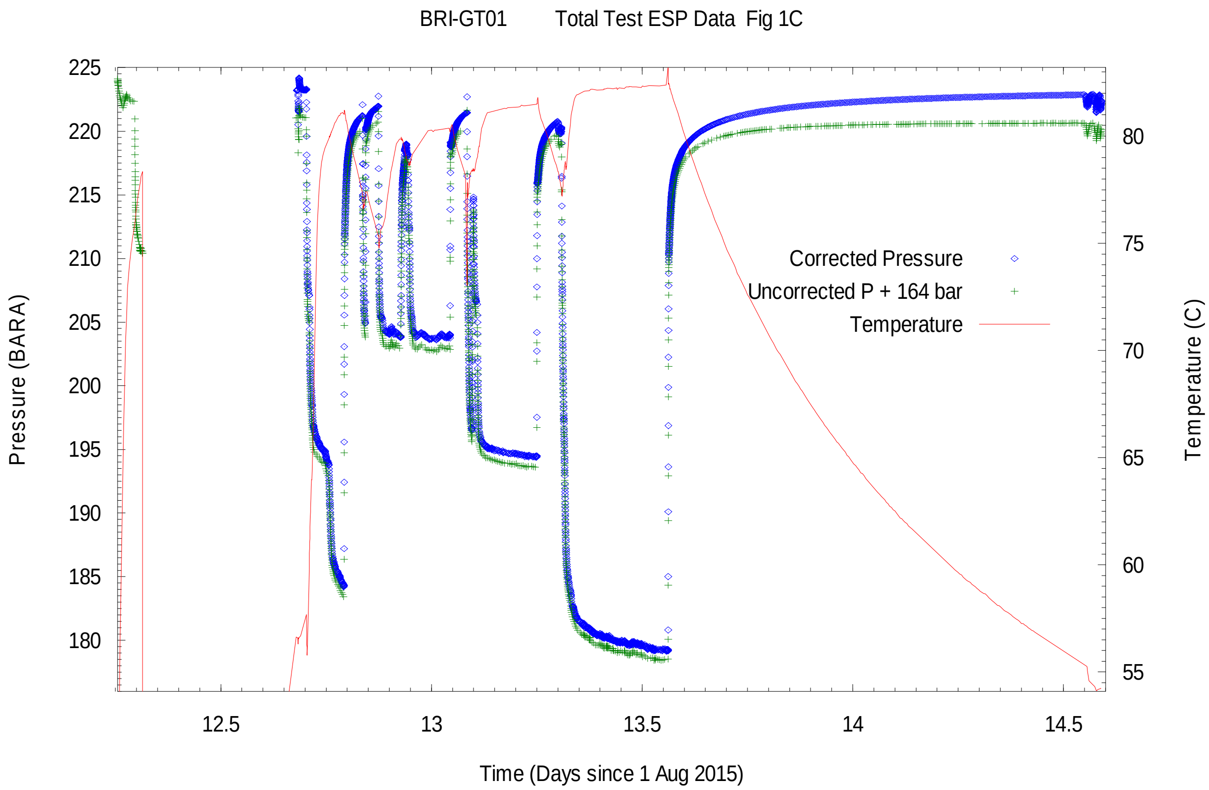
Fig-1 shows the original downhole gauge data together with the pressures corrected for the 100 m water column down to the datum depth of 2200 m tvBRT (minus 10 bar to plot close to the original pressures).

In Fig-1B, the same uncorrected pressures are presented together with the rate data.

Finally, in Fig-1C, the ESP data are presented, both the corrected pressures down to datum, using the formula as determined in chapter 3, as the uncorrected pressures (plus 164 bar for plotting).
The effect of the correction is clearly visible in the final build-up.
Note that the ESP data start after the clean-up and the first, 10 hours long, build-up.
As only the initial production pressures were available from the clean-up without shut-in pressures, this period has been added as pre-test data, not appearing on the analysis plot Fig05.




BRI-GT01 Pressure and Rate Data Fig 1B
Pressure (BARA)
Flowrate (m3/hr)
Pressure + 10 bar
Flowrate
Time (Days since 1 Aug 2015)
225
220
215
210
205
200
195
190
185
180
350
300
250
200
150
100
50
0
12.5
13
13.5
14
14.5


BRI-GT01 Total Test ESP Data Fig 1C
Pressure (BARA)
Temperature (C)
Corrected Pressure
Uncorrected P + 164 bar
Temperature
Time (Days since 1 Aug 2015)
225
220
215
210
205
200
195
190
185
180
80
75
70
65
60
55
12.5
13
13.5
14
14.5

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 pressure data

The downhole gauge pressures, corrected for the cooling water column of 100 m (which did hardly change the shape; only adding about 10 bar), see chapter 4, have been matched first with a two-layer model, with the larger thickness (420 ft) having a large skin of 25 and the rest (180 ft) a skin of 0.7.
The thicker layer has a permeability of 111 mD, the thinner layer of 176 mD. The vertical permeability of high-skin layer is 1.8 mD. The average reservoir permeability is 130 mD. The wellbore storage coefficient is 0.064 b/psi. The static reservoir pressure at the datum depth of 2200 m is 223.5 bara.
There is some evidence of a single flow barrier at 650 m distance from the wellbore.

Investigating what the effect of the 21 m (tv) of blind pipe would be, the bottom layer of the two-layer model was given an infinite skin. The 21 m was not sufficient to explain the two-layer effect.
However, when the thickness of this closed-off bottom layer was increased to 50 m and the flow barrier moved to 800 m, a similar good match was obtained. The permeability had to be somewhat lower at 120 mD.
The skin of the open 133 m was now 2.8 at the end of the production test. The vertical permeability of the bottom layer is 1.4 mD.

Fig02 presents the match of the main build-up, both the Horner “straight” line (dark blue) as its derivative (light blue). Note that the first minute can be matched as pure wellbore storage. Next for about 1 hour, the derivative shows severe wellbore effects, deviating far from the smooth model performance. But after 1 hour, the build-up can be matched very well with both two-layer models, Fig02Z.

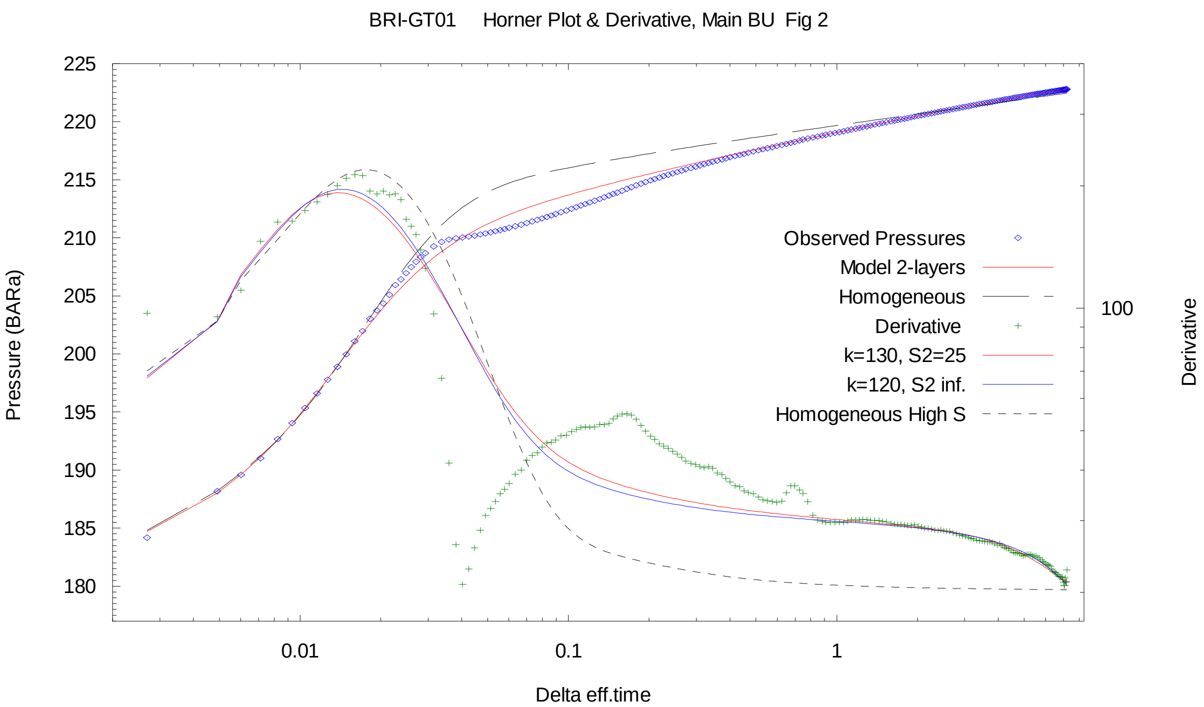
The radial model was matched in order to calculate the possible improvement of this well by cleaning up to a constant skin of -0.5 over the whole reservoir. The matched high skin model has a skin of 7.5 and a similar Productivity Index (PI) as the matched two-layer model. Replacing this skin of 7.5 with a low skin of -0.5 improves the PI from 6.8 to 13.6 m3/hr/bar. The resulting increase in flowing pressures can be seen in FIG03 (dotted brown line). Note the good match with the pressures on this scale of the radial high skin model. The special plot of FIG02 is really required to observe the difference.
FIG03 makes clear that the skin is increasing during the production test, as the model has clearly a too large skin during the first flow periods.

This is better demonstrated in FIG03B and Fig02BZ, showing the match of all flow periods for the same two-layer models, but matched on the first build-up plus the last flowing pressure before. The model with the two layers producing had to be changed: The good match of Fig2B of this first build-up has the best layer 150 ft (46 m) thick with a skin of -1.4 (!) and permeability of 180 mD; such a low skin seems very unlikely. Layer-2 is 450 ft (137 m) thick with a skin of 16.7 and permeability of 110 mD. The PI is 8.4 (55 hrs).

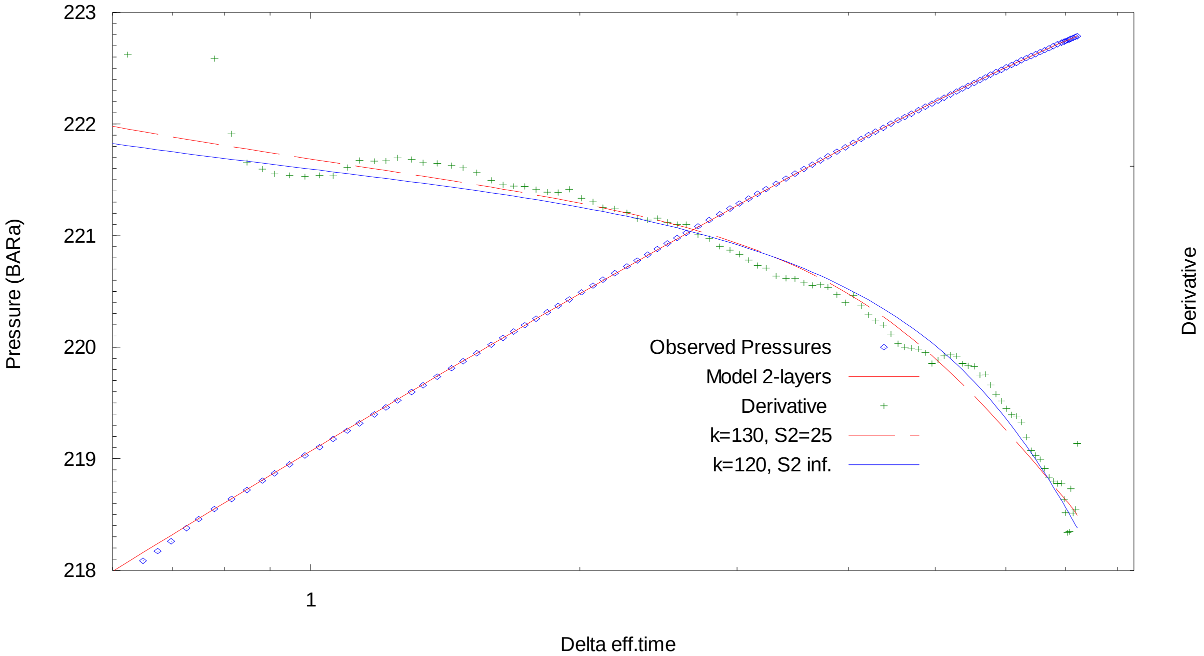
The model with the closed-off layer-2 has now an upper layer skin of only 0.3, but required a 62 m thick closed-off layer and an average permeability of 125 mD. In view of the strange S1 of the other model, this model seems much more likely than the two-layer model with both layers producing.

The Productivity Index (PI) of the two-layer model matched on the final build-up plus last flowing pressure before is 6.8 m3/hr/bar after 55 hours. This PI will continuously (slowly) decline until the injector stabilises the pressure in the concession area. Only after the interference test can this be calculated more precisely.
As a demonstration, the matched model has been used to forecast the pressure decline during a 3 months (2200 hrs) constant production rate of 298 m3/hr (45000 b/d).
The final PI, assuming of course no increase in skin, is 5.7 m3/hr/bar, Fig06.

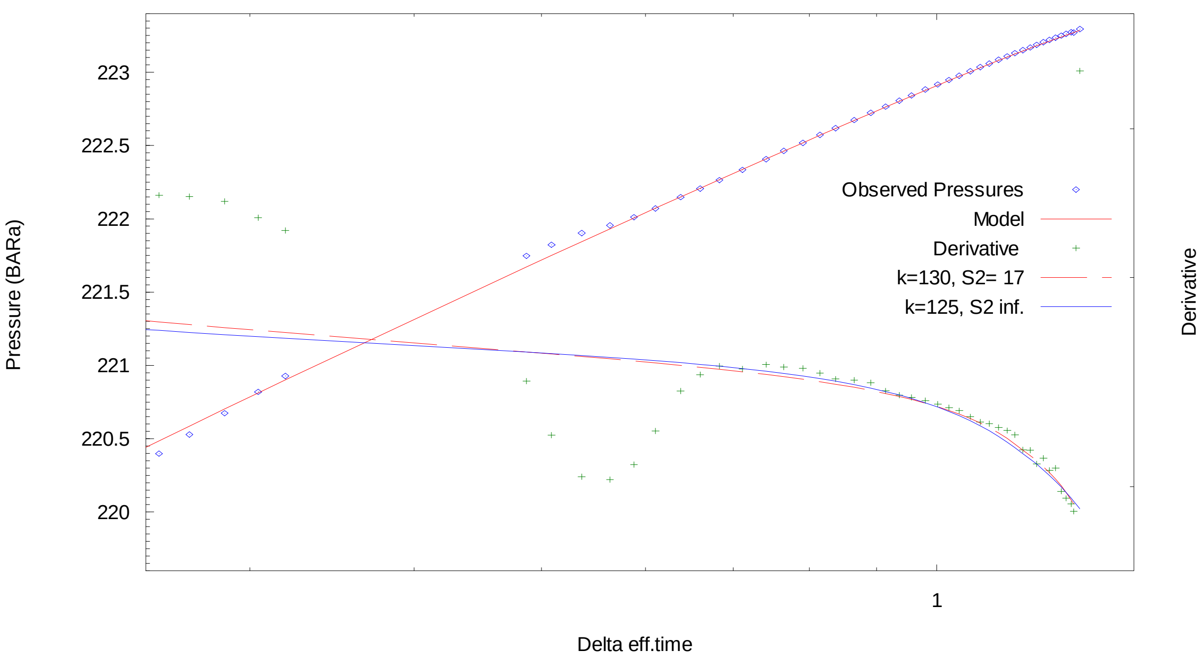
In order to investigate the accuracy of the correction formula with which the ESP pressures are extrapolated down to the datum depth 1580 deeper, the corrected ESP pressures have been matched with the same most likely two-layer model (S2 infinite) as matched on the deep gauge.
The best match has the same 2 layers but with S1 increased from 2.8 to 3 and the distance to the barrier had to be increased to 1000 m. The static reservoir pressure changed only from 223.50 to 223.54 bara.
For a less complex well, the ESP pressures are obviously sufficient.
Comparison of the flowing pressures of the deep gauge and the ESP, both extrapolated to datum, shows an extra pressure drop due to friction in the 1481 m of casing in between of 1 bar on a drawdown of 43.5 bar (only 2%).



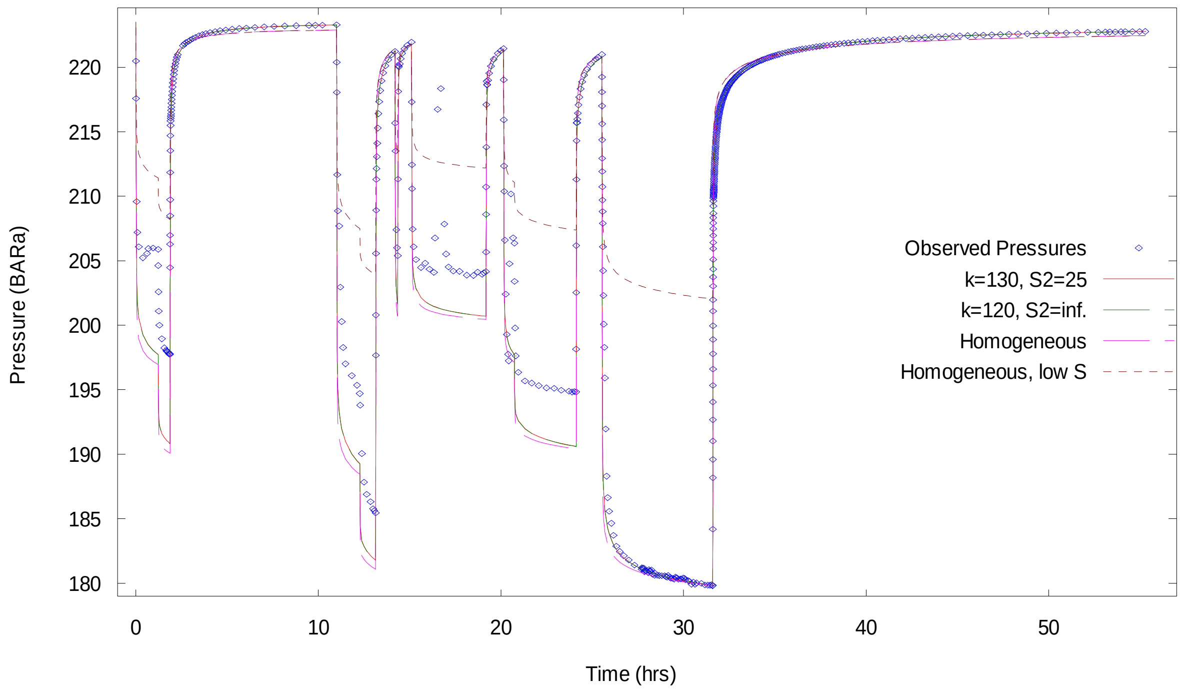
BRI-GT01 Horner Plot & Derivative, Main BU Fig 2Z



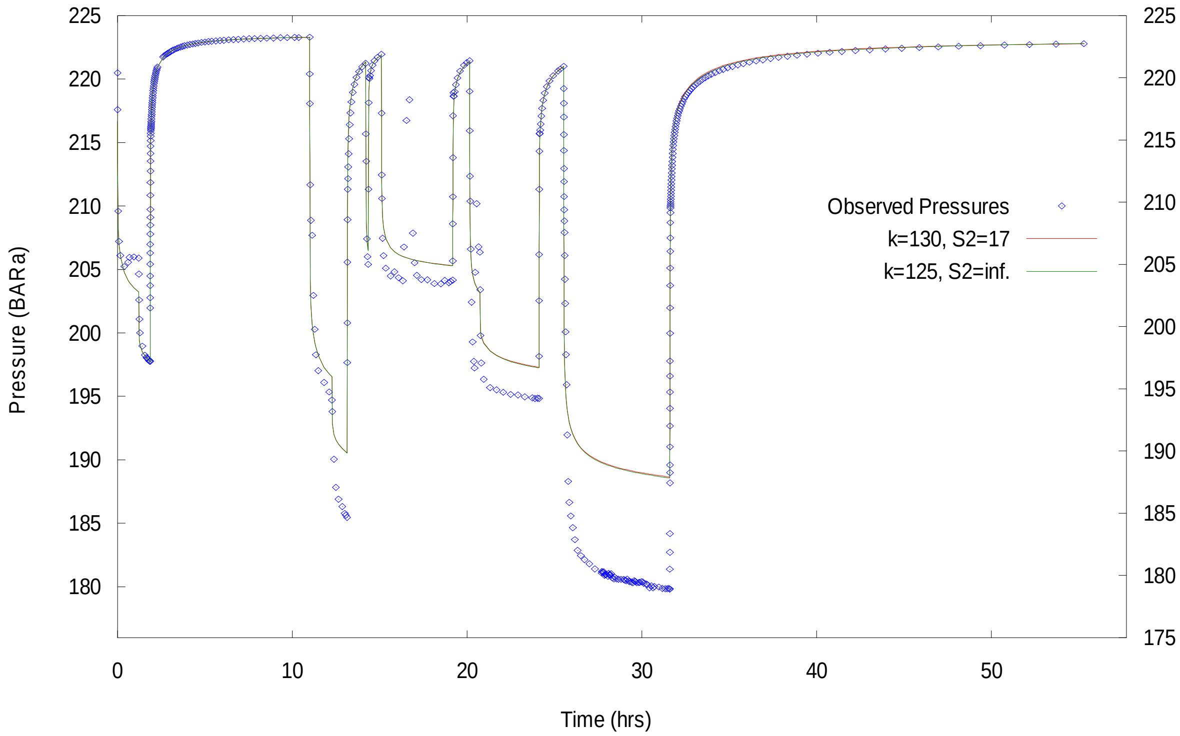
BRI-GT01 Horner Plot & Derivative, First BU Fig 2BZ

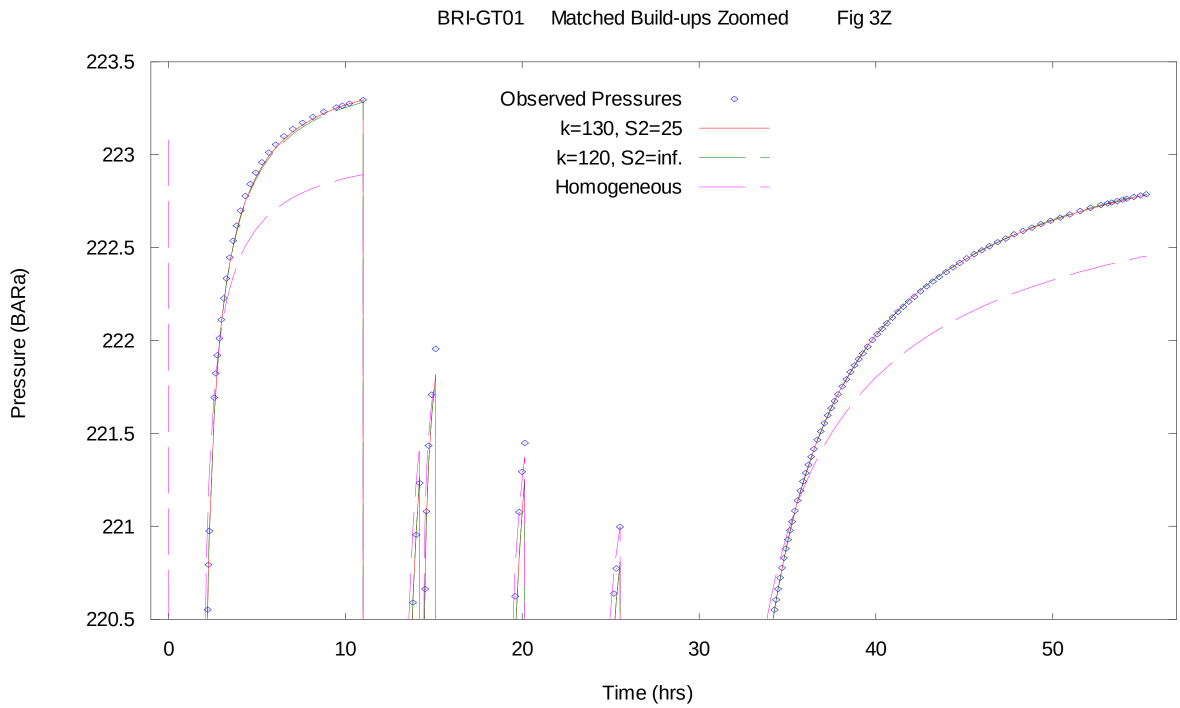


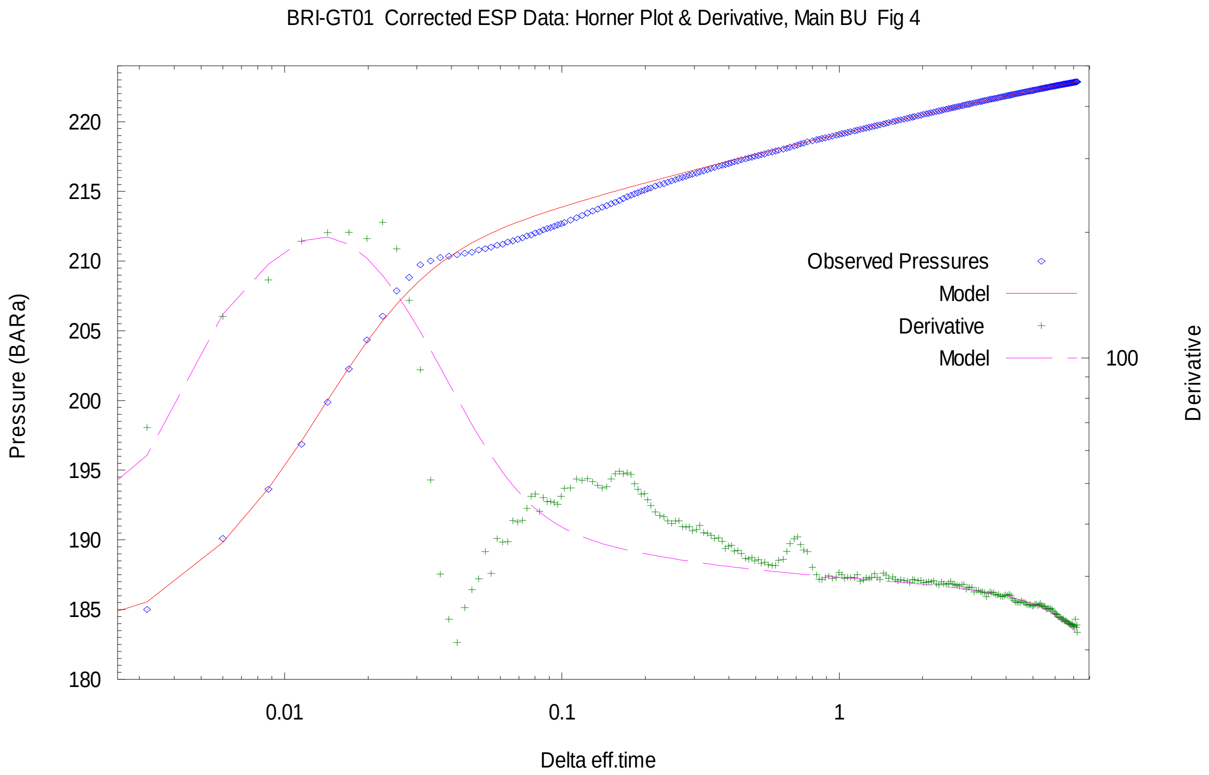
BRI-GT01 Matched Test History Fig 3

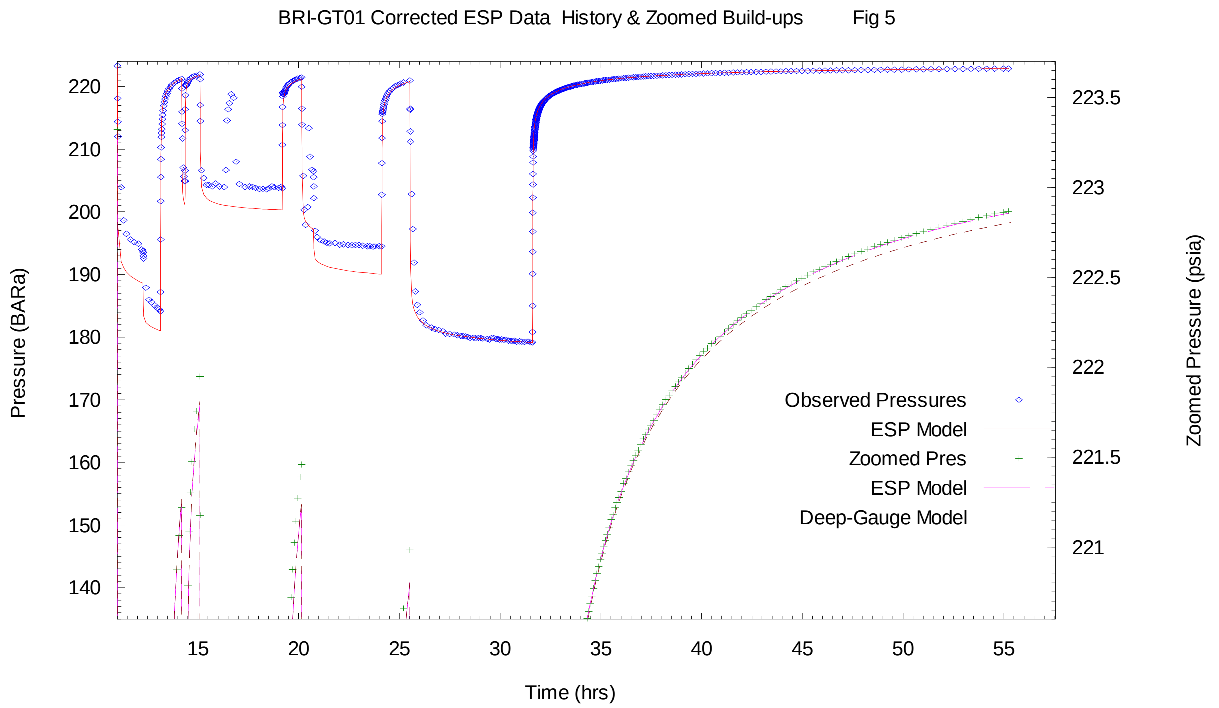


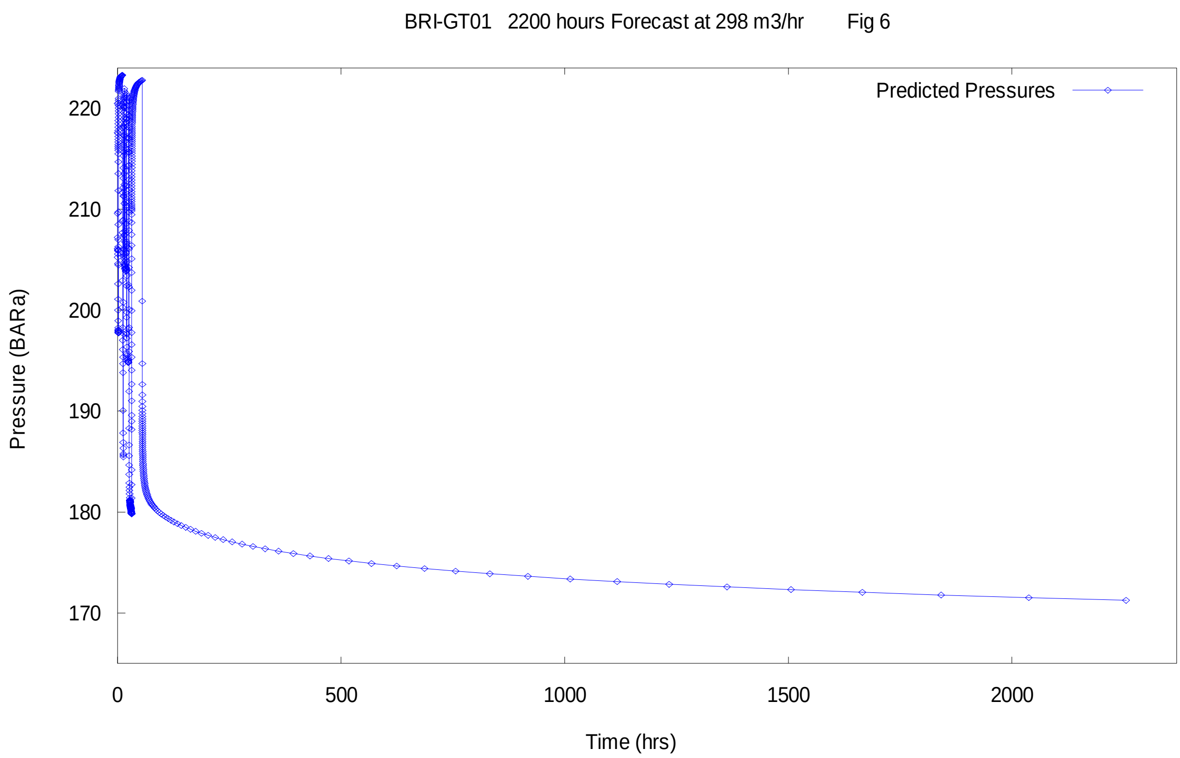
BRI-GT01 Press. History, Models Matched on First Build-up Fig 3B




BRI-GT01 Matched Build-ups Zoomed Fig 3Z
Observed Pressures
k=130, S2=25
k=120, S2=inf.
Homogeneous
Pressure (BARa)
223.5
223
222.5
222
221.5
221
220.5
0
10
20
30
40
50
Time (hrs)

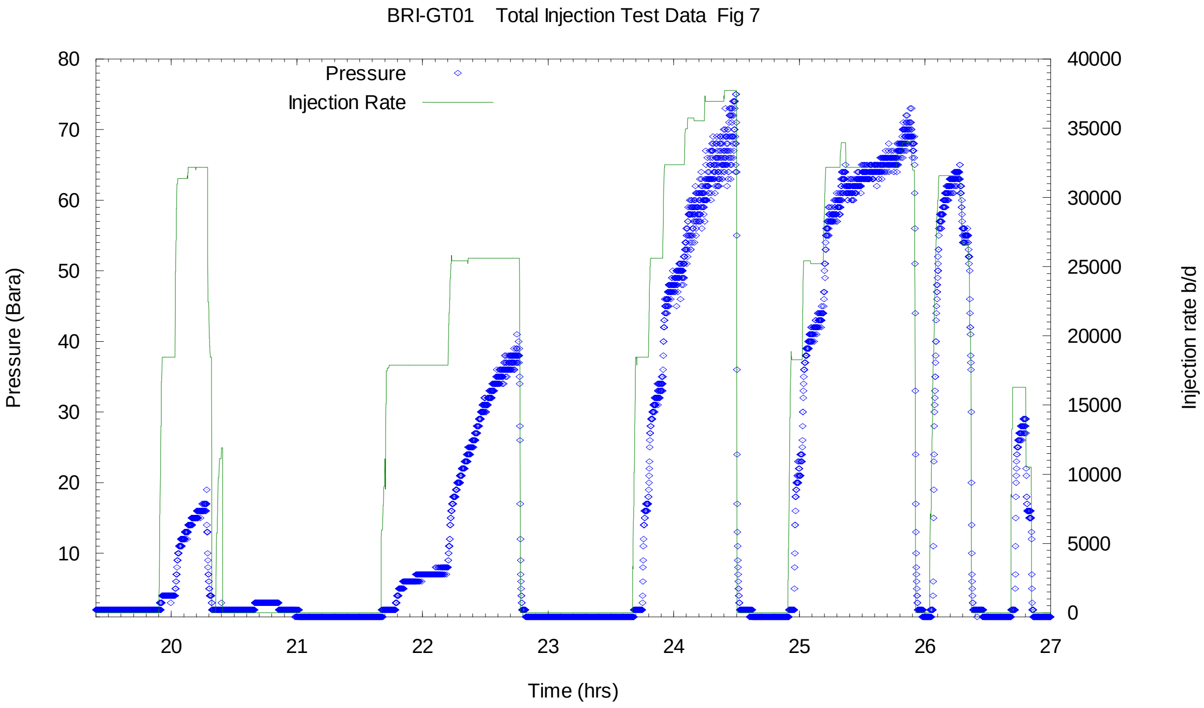

BRI-GT01 Corrected ESP Data: Horner Plot & Derivative, Main BU Fig 4
Observed Pressures
Model
Derivative
Model
Pressure (BARa)
220
215
210
205
200
195
190
185
180
100
Derivative
0.01
0.1
1
Delta eff.time


BRI-GT01 Corrected ESP Data History & Zoomed Build-ups Fig 5
Pressure (BARa)
Zoomed Pressure (psia)
Time (hrs)
Observed Pressures
ESP Model
Zoomed Pres
ESP Model
Deep-Gauge Model
220
210
200
190
180
170
160
150
140
223.5
223
222.5
222
221.5
221
15
20
25
30
35
40
45
50
55


BRI-GT01 2200 hours Forecast at 298 m3/hr Fig 6
Pressure (BARa)
Time (hrs)
Predicted Pressures
220
210
200
190
180
170
0
500
1000
1500
2000

7 Analysis of injection data

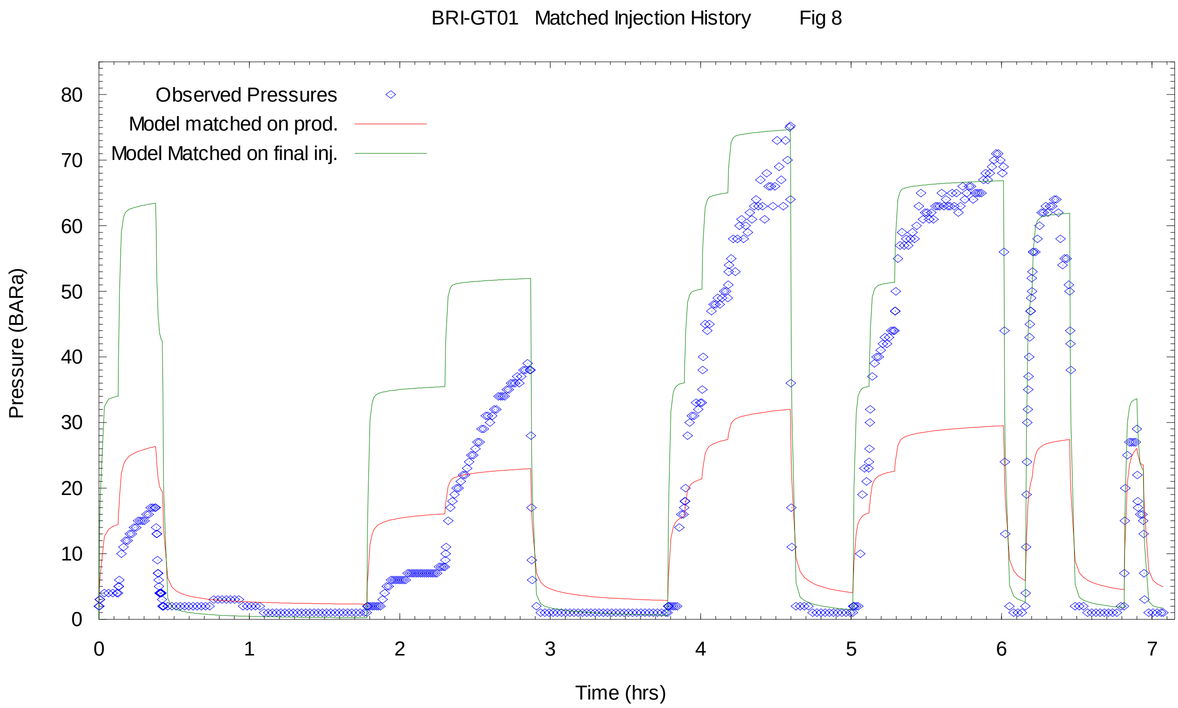
In Fig-8, the surface pressures are presented together with the rate data during the water injection on 15-16 August 2015.



This injection history has been matched with the same two-layer model as matched on the production test data. The Initial model in Fig08 is the same two-layer model as matched on the final production rate during the production test. It seems that the very first injection did better than this model, but the injection period was too short to draw firm conclusions. From the subsequent injection periods it is very clear that the skin is increasing during injection.

To match the two-layer model (with the bottom layer having an infinite skin) on the 3 final injection periods, the skin of top layer had to be increased from 3 to 19, resulting in a final injectivity index (transient after 7 hrs) of only 3.1 m3/hr/bar. Initially this PI was 7.3 m3/hr/bar, of course somewhat higher than the PI after 55 hours mentioned in chapter 6.

Apparently, something is plugging-up the open screens.



8 Conclusions and Recommendations

The main conclusion is that the lack of a radial-flow period in the Horner plot of the main build-up makes the determination of the average permeability uncertain.
However, trying a higher k than the 120-125 mD from the most likely model resulted always in a poorer match.
The range in possible average permeability can thus be assumed to be between 110 and 150 mD.
All these permeability values assume that the whole net thickness of 183 m is contributing to the water production. As there is no evidence of shale layers in this reservoir this is highly likely.

The evaluation with the second two-layer model agrees with the completion data and the detailed analysis of both the first and last build-up. The lower section of the well, along the blind pipe and some 30 m above, seems to be shut-off from the reservoir by this blind pipe and a very high skin.

The presence of a flow barrier at about 800 from the wellbore is deduced from comparison of the static pressures after the clean-up and after the whole production test but also improved the matches.

The increase in skin of the upper 70% of the reservoir during both the production test and during the subsequent injection is worrying and may partially be caused by a possible lack of an effective cleaning procedure, leaving fines both in the wellbore and in the reservoir around the wellbore, resulting in a skin on the screens. During injection this film may be moved to plug the formation.
A possible remedial action could be injection of a batch of the proper weak acid to dissolve fines from the mud used during drilling.

The equation to correct ESP pressures for the changing weight of the water column down to the reservoir seems to work reasonably well for the build-up data more than one hour after shut-in. If the next well is completed properly with an effective cleaning procedure (injection of a weak acid pill?), and radial flow is expected, no downhole gauge should be necessary.