3.6.7 Summary

To compare the well performance sensitivities, the low, mid and high gas-rates were looked up at a reservoir pressure of 120 bar and THP of 80 bar. It should be noted that the Prosper base case permeability for vertical well inflow of 200 mD is not conform the dynamic model, it should be ca 600 mD. Results are summarised below:

Sensitivity	Well	Base	Low	High	Base [MM sm3/d]	Low [MM sm3/d]	High [MM sm3/d]	Low	High
Skin	Vert	0	10	0	2.30	2.20	2.30	-4%	0%
	Hor	0	10	0	2.70	2.10	2.70	-22%	0%
Permeability [mD]	Vert	200	100	1000	2.35	1.70	3.70	-28%	57%
	Hor	50	10	100	2.70	1.10	3.10	-59%	15%
CGR [m3/m3]	Vert	3 (0.5)	56 (10)	0	2.35	2.28	2.35	-3%	0%
(stb/MMscf)	Hor	3 (0.5)	56 (10)	0	2.69	2.60	2.70	-3%	0%
WGR [m3/m3]	Vert	0	56 (10)	0	2.35	2.05	2.35	-13%	0%
(stb/MMscf)	Hor	0	56 (10)	0	2.70	2.00	2.70	-26%	0%
Roughness [inch]	Vert	0.00015	0.005	0.00005	2.32	2.07	2.39	-11%	3%
	Hor	0.00015	0.005	0.00005	2.70	2.07	2.81	-23%	4%
Tubing-size OD [inch]	Vert	7 5/8"	5.5"	9 5/8"	2.30	1.60	2.60	-30%	13%
	Hor	7 5/8"	5.5"	9 5/8"	2.60	1.40	3.95	-46%	52%

Table 3-4 Well performance sensitivity values summary at P_res 120 bar and THP 80 bar

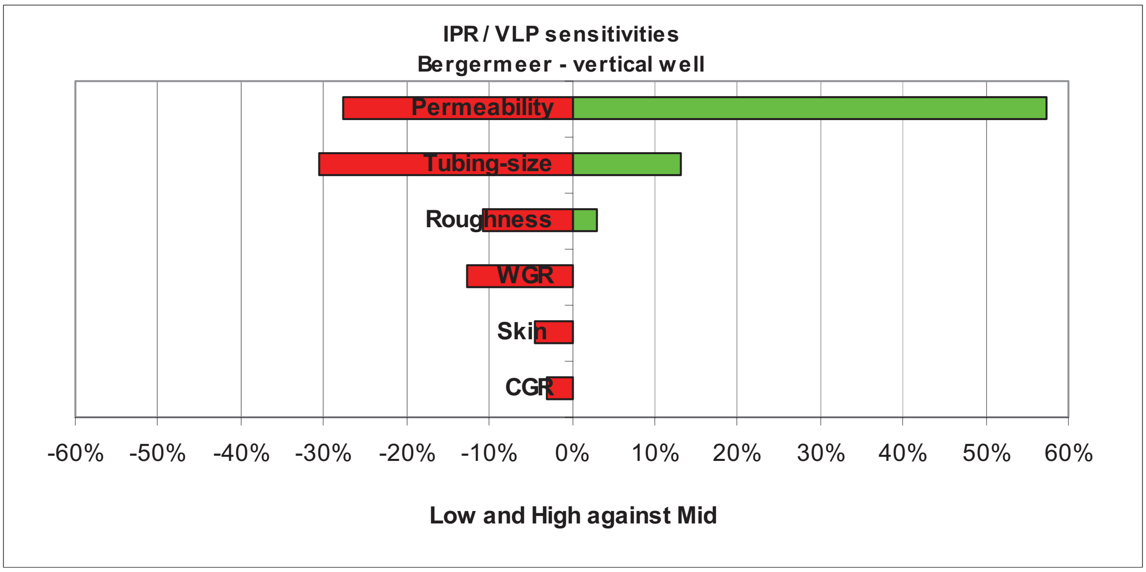

Figure 3-20 Tornado plot vertical well performance sensitivities at P_res 120 bar and THP 80 bar. Parameter ranges are shown in Table 3-4.

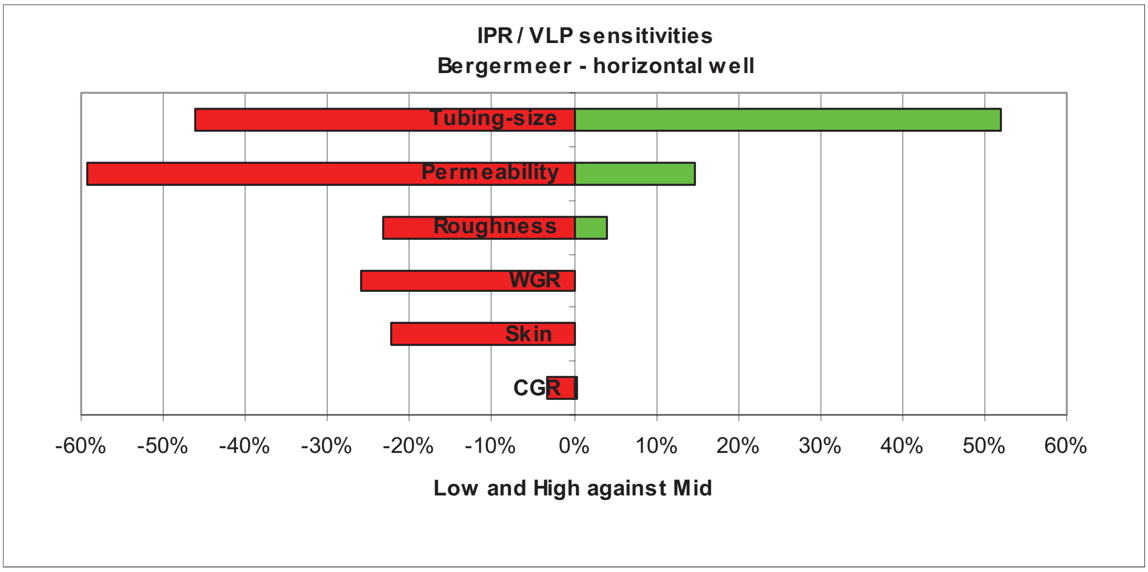

Figure 3-21 Tornado plot horizontal well performance sensitivities.

4 Summer Injection Test Interpretation

In order to improve understanding of historical reservoir dynamics and predict its behaviour during storage operations, an injection test was designed. In specific the purpose was to

- determine the volume distribution between the Main and BGM-7 blocks
- survey the gas-water-contact movement
- evaluate the pressure behaviour of BGM-7 to identify fault transmissibility between the Main- and BGM-7 blocks
- determine the reservoir permeability / porosity-compressibility between injection and observation wells
- calibrate the dynamic reservoir model with pressure behaviour seen during test

4.1 Summer Injection Test Forecasts

Gas was to be injected in BGM-1, BGM-2 and BGM-6 in the Main block. The injection test was planned according to the injection scheme in Table 4-1, the duration was estimated at 10 weeks and total injection gas of 126 MMm3. Well-surveillance was planned to be carried out before, during and after this summer injection test. Tools for pressure-measurements during injection were installed before the start. The overview of the proposed interventions:

- Pressure & Temperature gauge installation before summer injection test in: BGM-5, BGM-6 and BGM-7
- GWC measurement in BGM-3
- GWC measurement after injection in BGM-1
- Pressure measurement after summer injection test in BGM-1 or BGM-5

The expected pressure response is given in Figure 4-1.

Note that with the old History Match model, the wells were expected to be equalized instantaneously at the end of the injection period. A pressure-rise was modeled of ca 3.5 bar for the Main block due to injection of ca 200 MMsm3 in three months. The reaction in BGM-7 was expected to be small; only a small delay in the equalization process between the Main and BGM-7 blocks was forecasted. The fault between the BGM-7 and Main does not have a threshold pressure in the model and the pressure difference between the blocks is ca 20 bar, the Main block being at ca 9 bars and BGM-7 at ca 29 bars.

[deleted text because of confidentiality]

Table 4-1 Planned injection scheme [4].

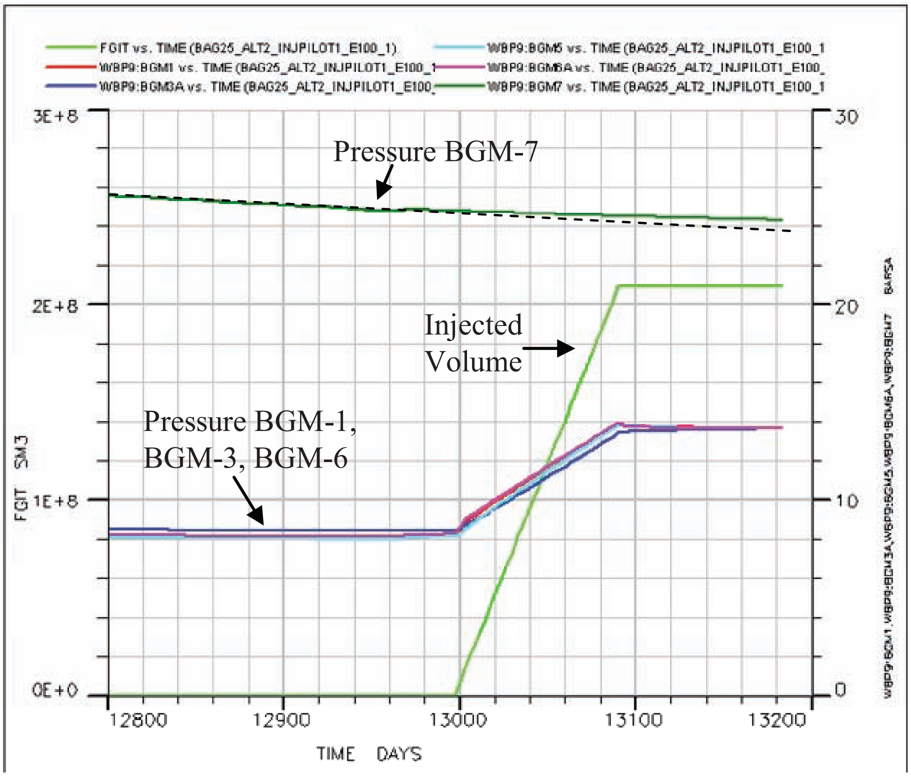

Figure 4-1 Predicted pressure behaviour summer injection test, MAIN block volume 13.6 Bcm, BGM-7 block volume 4.0 Bcm, base case model, no aquifer, Qinj 0.75MM sm3/d for 3 months in BGM-1, 2 and 6A (total 200 MM sm3) [Based on 'cont_mid' realization [1].]

4.2 Injection test data overview

During the summer of 2007, a gas injection test was carried out in wells BGM-1, BGM-2 and BGM-6. A total of 116 MMsm3 was injected in the reservoir in 10 weeks at rates between 0.4 and 1.0 MM m3/d. Downhole pressure and temperature monitoring was carried out during the test in wells BGM-5 and BGM-7. Additional gauges were placed in BGM-6 during injection in order to calibrate well injection models and possibly obtain data for pressure transient analysis. During running of the gauges, extra stops were made to provide a well temperature profile.

The first well to start injection was BGM-1 on July 24th at a rate of ca. 0.5 MMm3/d, well BGM-6 started on August 1st at ca 0.4 MMm3/d and BGM-2 started injection on August 6th at ca 0.4 MMm3/d. An overview of the actual well injection rates is given in Table 7-1 in the Appendix. Figure 4-3 shows both injection rates and THP of the wells. Duration of the test was until October 1st, when injection was halted simultaneously in all three wells. During the period a total volume was injected of 116 MM m3 (BGM-1 52.7, BGM-6A 38.6, BGM-2 24.7 MM m3). The unstable gas-rate in BGM-2 at the end of injection is due to incorrect metering.

Observation of the bottom-hole pressure in BGM-7 revealed that the well did not respond to the injection test in the main compartment during the measured period (Figure 4-4). Being at a higher pressure than the main block (29 bar vs 9 bar) and in the absence of an aquifer, the expectation was that the well would be equalizing slowly with the main block, dropping ca 0.2 bar during the injection period. It is possible that the reaction in this well will be delayed, therefore another pressure-measurement (e.g. April 2008) in this well is highly recommended.

Well BGM-5 is located ca 800m north of well BGM-2 and 500m south of BGM-1 in the main compartment (Figure 4-2). The pressure response in this observation well due to the injection test is slower than expected; compare Figure 4-5 with Figure 4-1. It is possible that a non-sealing fault exists between BGM-5 and BGM-1; see the well-interpretation in the next section. At the end of the injection period on October 1st, the pressure in observation well BGM-5 was 10.2 bar, far from the expected 12 bar, but still increasing. On November 6th, before the gauges were taken out, the BHP measured 11.1 bar. The pressure trend was extrapolated to reach 11.65 bar, see paragraph 4.3.

The pressure gauges were taken out of BGM-6 on August 27th, at a SBHP of approx. 13.6 bar. The next BHP survey was done on November 7th, more than a month after the injection test. The SBGP measured ca 13.1 bar. The survey was repeated on December 10th, when it measured 13.0 bar, a decrease of ca 0.1 bar in a month. The pressure-difference between BGM-5 and BGM-6 could also be explained by the existence of a baffle (non-sealing fault) between the two wells. Apart from the shut-in period at the beginning of the pressure measurements in well BGM-6, the data could not be used to calibrate the well injection model. The pressure data was too much influenced by the varying injection rates in wells BGM-1 and BGM-2 to use it as a model for rate dependent skin.

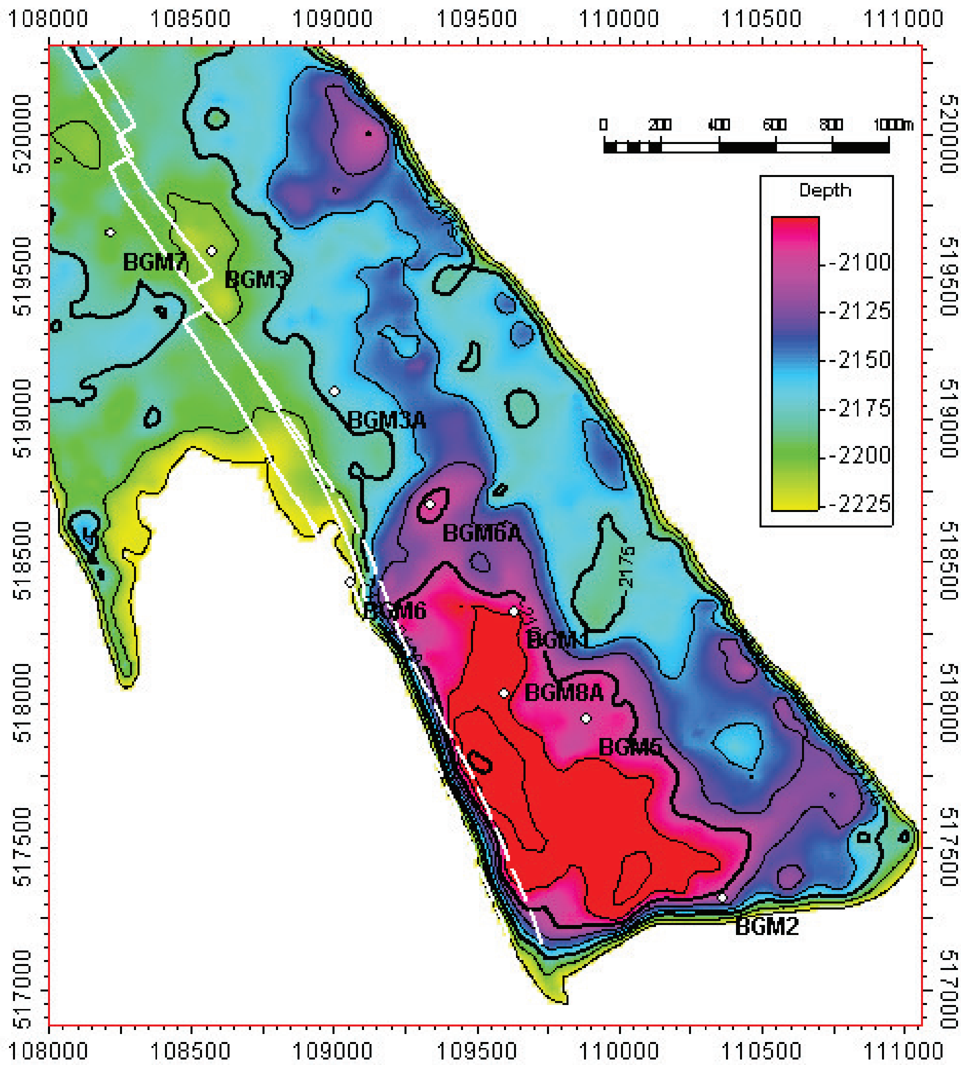

Figure 4-2 Zoom-in on the BGM well area, to indicate the relative positions of the wells. The (partly inferred) line between BGM7 and BGM-main blocks is indicated with white lines. The map shows top reservoir, where it is above the original GWC.

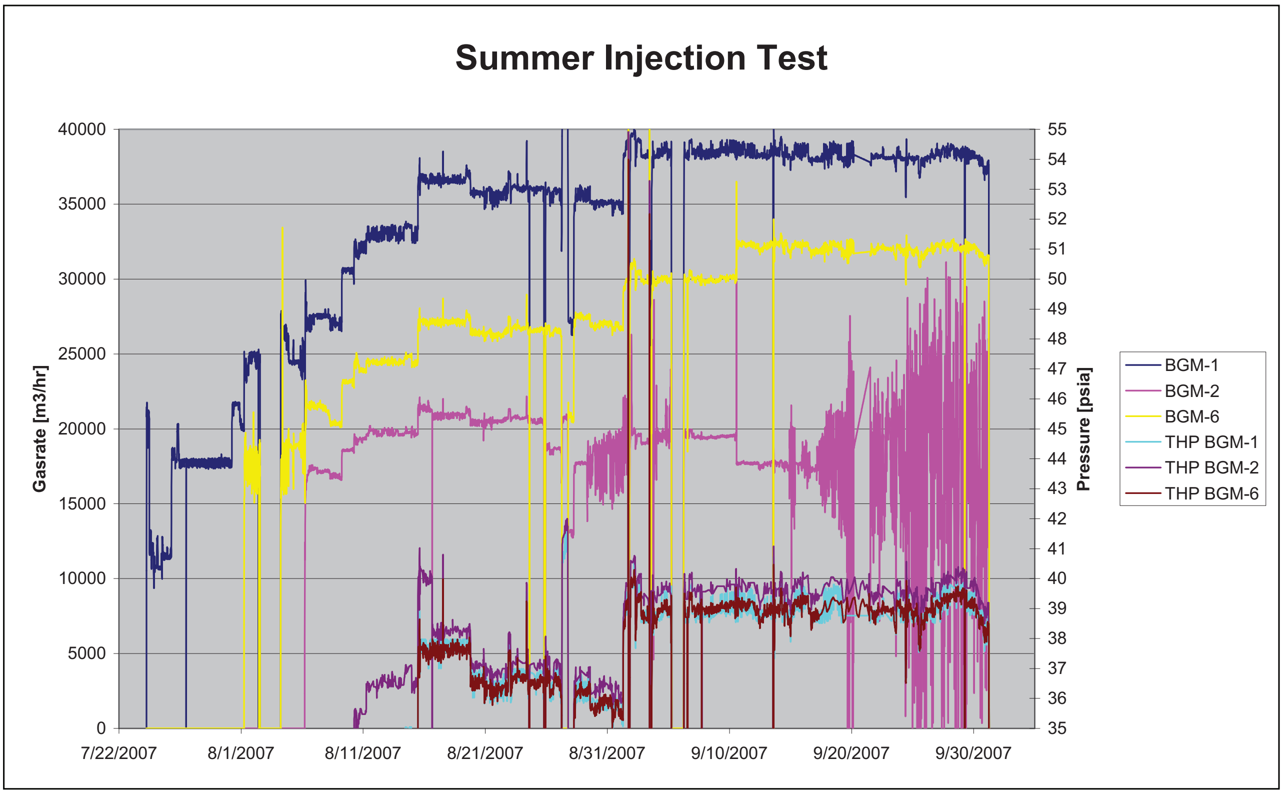

Figure 4-3 **Overview of injection rates and well head pressures of wells BGM-1, BGM-2 and BGM-6 during 2007 Summer Injection Test.**

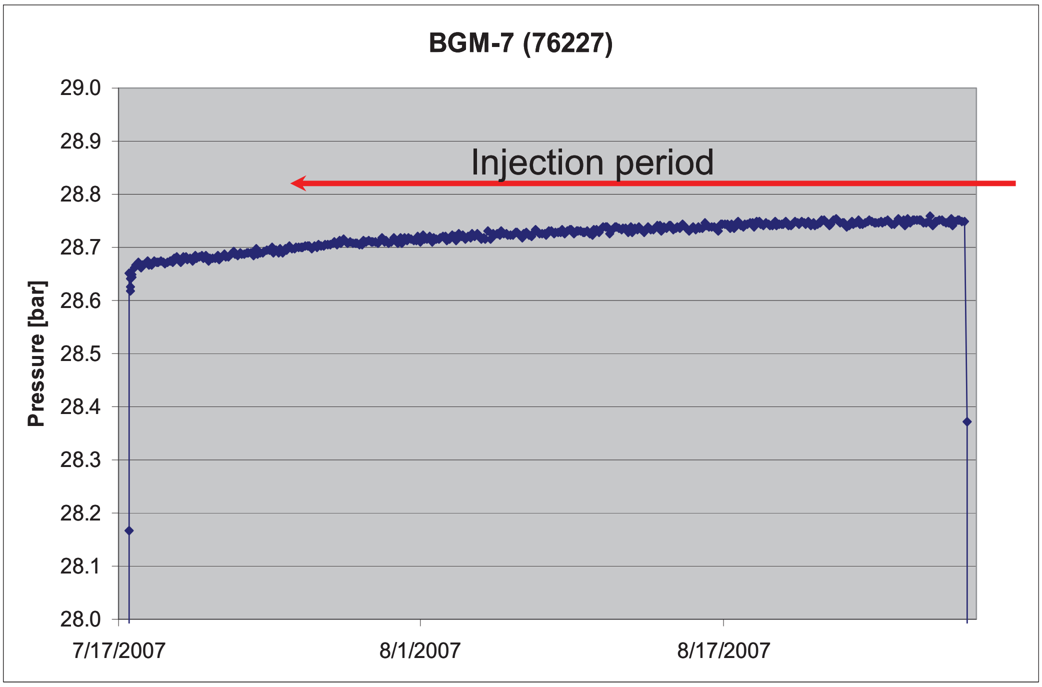

Figure 4-4 **BGM-7 BHP before and during summer injection test**

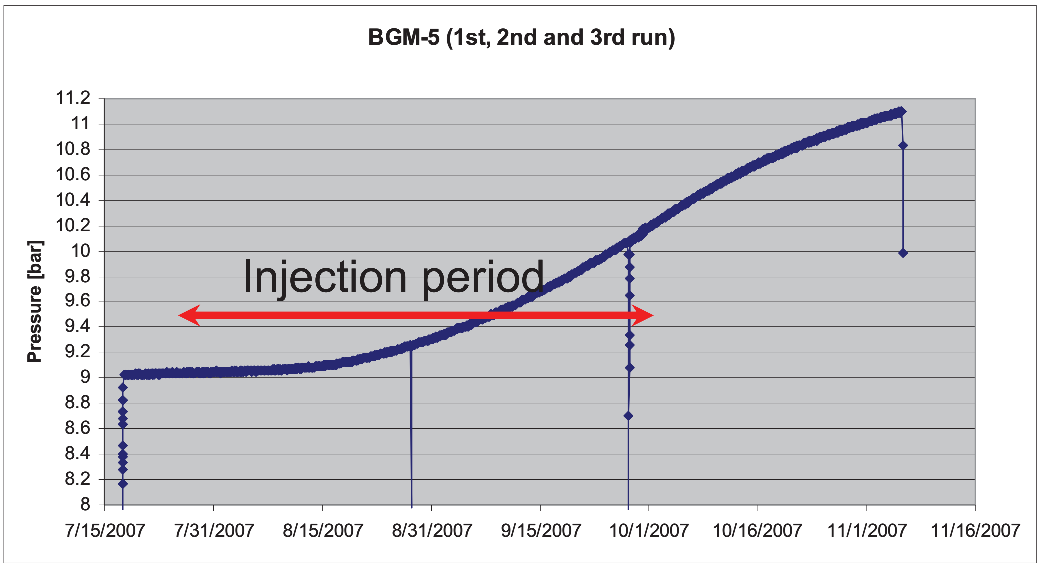

Figure 4-5 **BGM-5 BHP before, during and after summer injection test, 1st run gauge 76760, 2nd run gauge 76391, 3rd run gauge 76799**

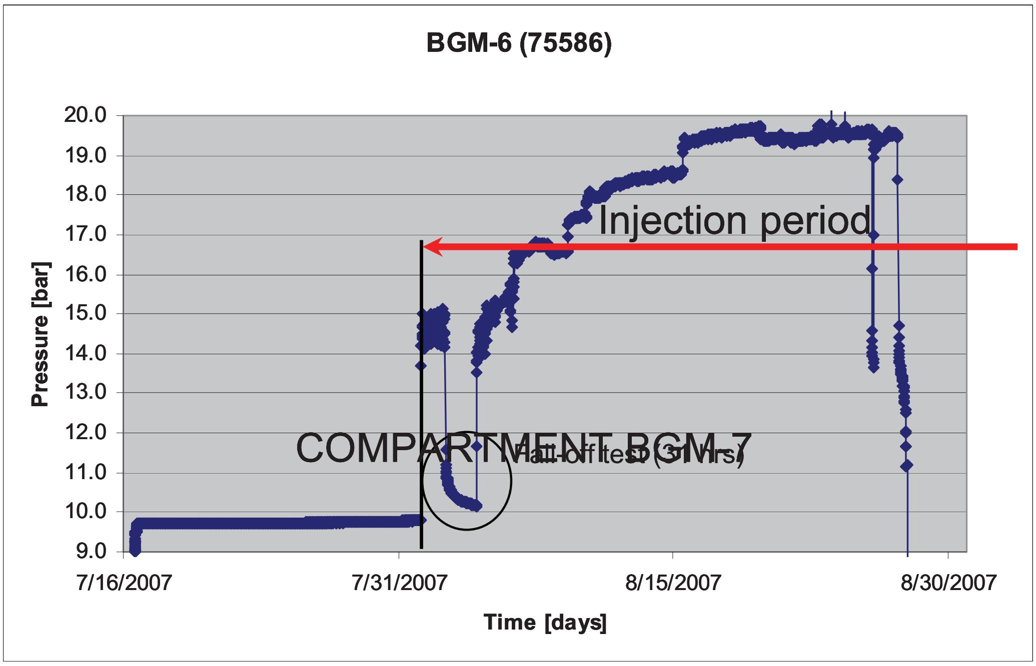

Figure 4-6 **BGM-6 BHP before and during summer injection test**

4.3 Summer Injection Test Interpretation

The summer injection test was interpreted using Ecrin/Kappa software, version 4.02. A table of the injection data and detailed analysis results can be found in Appendix I. Because of downhole restrictions no gauges were put in injection wells BGM-1 and BGM-2. BGM-5 and BGM-7 were used as observation wells.

BGM-7

The well was observed downhole during the first month of injection. The pressure slightly increased during the measured period with ca 0.05 bar. It can not be said whether this was due to injection in the wells on the other side of the fault or due to gauge accuracy or temperature effects. As the well was expected to decrease in pressure with 0.2 bar during the period, it is possible that fault transmissibility is lower than in the (history matched) model or that the fault has a threshold pressure greater than the current difference of ca 20 bar. It is advised to observe the pressure again in a few months time.

BGM-6

At the start of the injection test, well BGM-6 was shut-in for almost two days on August 2nd, after having flowed for 31 hours. The shut-in period showed a gradual decline in reservoir pressure from 11 to 10.1 bar, see Figure 4-6. The fall-off was interpreted under the assumption that it was not yet influenced by injection in neighbouring well BGM-1. The interpretation resulted in extrapolated reservoir pressure (P_res) of 10.0 bar, KH 22400 mD*m, K 187 mD, Skin -0.4, see Figure 7-1, Figure 7-2 and Figure 7-3 in the Appendix. After the shut-in, the BHP becomes too much influenced by injection in the other wells to individually analyse the pressure data.

The pressure gauges were taken out of BGM-6 on August 27th, at a SBHP of approx. 13.6 bar. The next BHP survey was done on November 7th, more than a month after the injection test. The SBGP measured ca 13.1 bar. The survey was repeated on December 10th, when it measured 13.0 bar, a decrease of ca 0.1 bar in a month.

BGM-5 Interference test

For interpretation of the pressure behaviour of observation well BGM-5, the injection rates of wells BGM-1, BGM2 and BGM-6 had to be added, with a single fictive injection well placed at 750 m, which is roughly the distance between BGM-5 and injection wells BGM-6A, the injector that is located at the furthest distance from BGM-5. After retrieval of the second gauge run, the BHP data covering the injection period was interpreted. This resulted in average KH 23500 mD*m, K of 178 mD and Phi 0.22, see Figure 7-4. The permeability thus found was lower than the average permeability in the model of ca 600 mD. This was explained by the fact that the interference test interpretation is more influenced by heterogeneities in the field than a single well test interpretation. These heterogeneities could be calcite streaks or sub-seismic faults.

The same interpretation was repeated for a distance between injectors and producers of 500m, or the distance between BGM-5 and BGM-1 which is the best injector and located closest to BGM-5. The interpretation resulted in KH 10000 mD*m, K 76 mD and Phi 0.27, see Figure 7-5. The permeability is 100 mD lower than in the previous interpretation for the injector at 750 m.

After retrieval of the 3rd gauge run, interpretation of the injection period clearly showed insufficient pressure build-up at the end of the shut-in period, see Figure 4-7. The parallel boundaries were set at 350 and 700 m, to represent the geological model. The average distance between the injectors and BGM-5 of 710 m was chosen, which resulted in KH 17400 mD*m, K 132 mD and Phi 0.22, see the log-log plot Figure 7-8. The semi-log resulted in 190 mD, see Figure 7-7. The effect of changing rock compressibility was checked on the well test. The base case value of 5.5e-5 bar-1 was changed to a 10-4 and 10-5 bar-1, to see if this would change the outcome significantly. This was not the case.

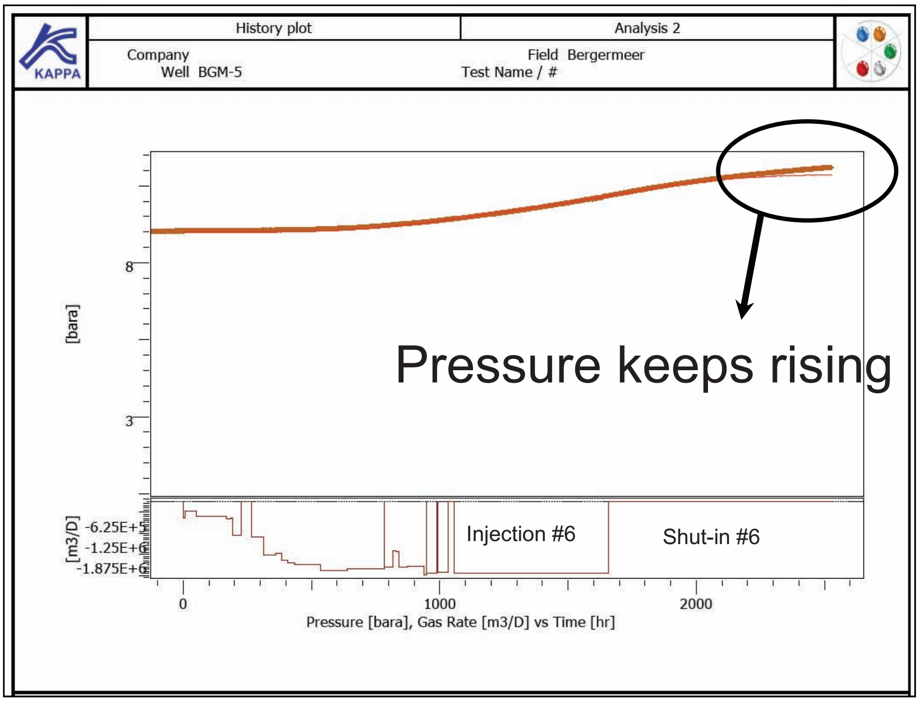

Figure 4-7 BGM-5 BHP interpretation of injection period interference test, parallel faults

From interpretation of the final build-up it was concluded that the SBHP could only be matched with a closed compartment system; BGM-5 surrounded by faults to the west, south and east, and an additional fault north of BGM-6, see Figure 4-8. The northern fault was put in the model as a baffle, with a seal factor of 0.001, constraining injection to the southern part of the Main block. The second fault, south of BGM-6, had a seal factor of 0.1 in the model and was put in to delay the pressure response in BGM-5. In the dynamic model, the fault north of BGM-6 was retained, while the fault south of BGM-6 was moved south of BGM-1 because BGM-1 and BGM-6 showed similar CITHP pressures (email TAQA, November 21th). Figure 4-9 shows the pressure match of the shut-in period.

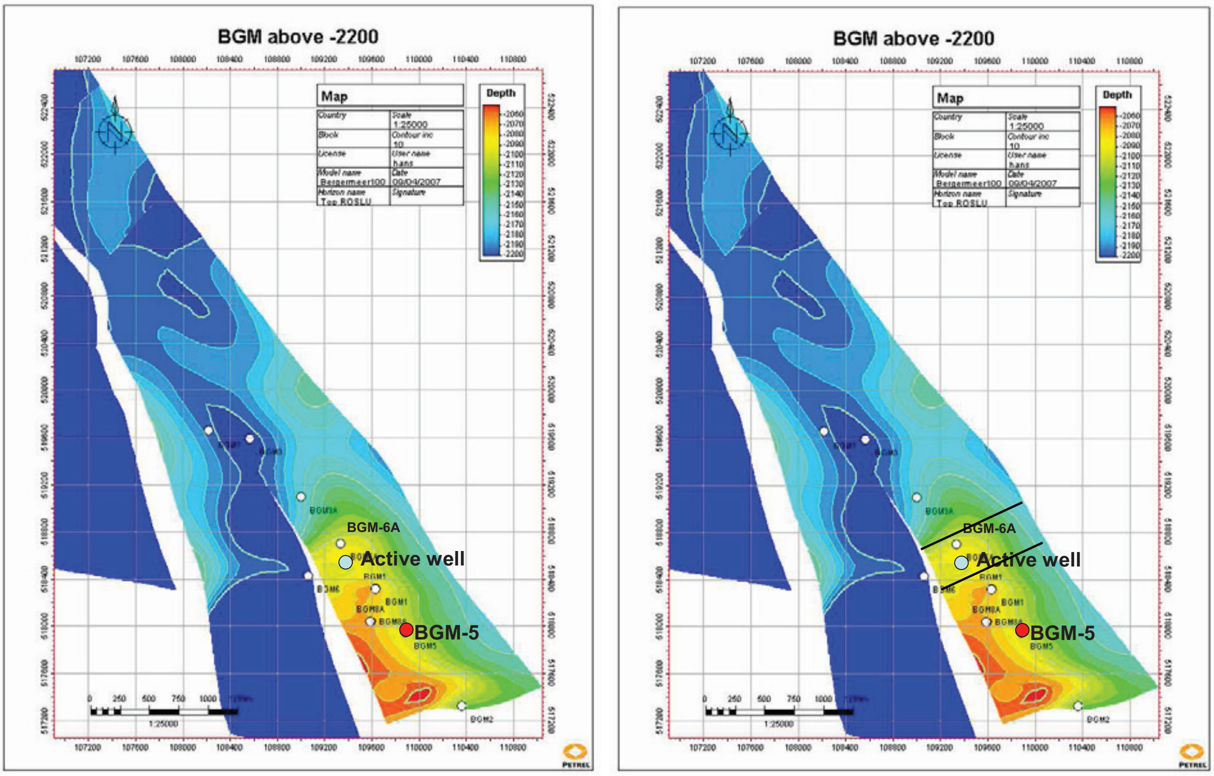

Figure 4-8 Structural model of Bergermeer as used for well test interpretation, injector at 710 m from observation well BGM-5, left: open compartment with parallel faults, right: closed compartment with non-sealing fault above BGM-6.

The final reservoir pressure of BGM-5 was extrapolated from the pressure build-up seen during the 3rd gauge run. It is 11.65 bar, some 0.5 bar higher than the last point measured at 11.1 bar on November 6th, see Figure 7-10. The match was obtained with a permeability of 135 mD (Figure 7-9), while the semi-log calculated permeability was 353 mD (Figure 7-10). An overview of the interference test results is given in Table 4-2.

The reservoir pressure-difference between the BGM-5 (11.65 bar) and BGM-6 (13.0 bar on December 10th) of ca 1 bar is further evidence of the possible existence of a baffle (non-sealing fault) between the two wells. The time it will take to equalize the two blocks will give an indication of the fault transmissibility. If the two blocks in the south of the Main compartment will not equalize, this could be explained by a small threshold pressure over the fault. The faults were further studied with the numerical model, see next section.

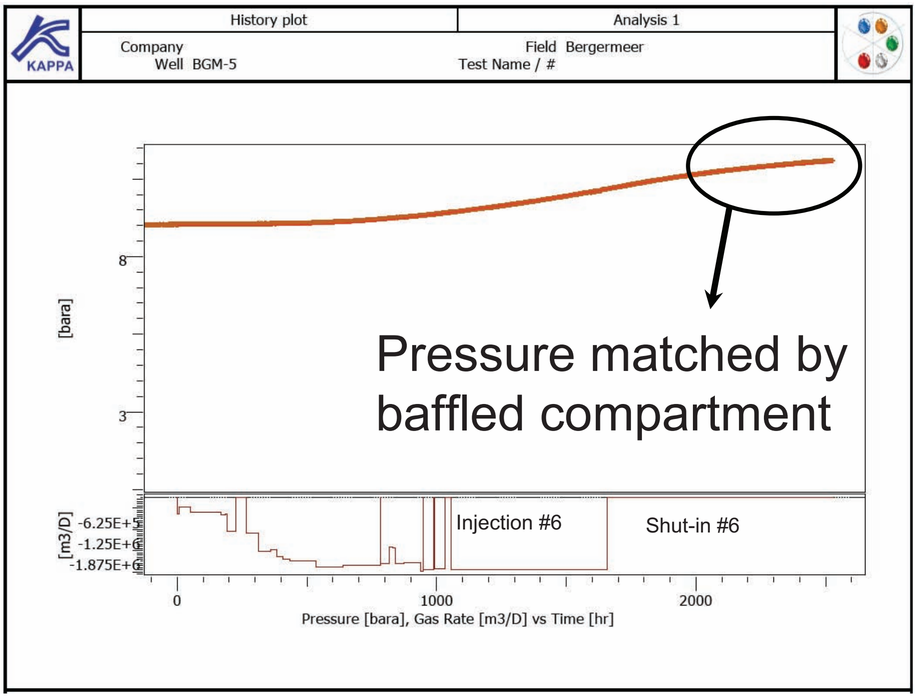

Figure 4-9 **BGM-5 BHP interpretation of shut-in period interference test in closed compartment.**

Interpretation input data	Well-distance injectors [m]	Boundary-model	KH [mD*m]	Phi [%]	Perm. [mD]]
Injection test after 2nd run	750	Parallel faults, 350 / 700 m	23500	22	178
Injection test after 2nd run	500	Parallel faults, 350 / 700 m	10000	27	76
Injection test after 3rd run	710	Parallel faults, 350 / 700 m	17400 - 25000	22	132 – 190
Shut-in test after 3rd run	710	Compartment, faults @ 350, 700, 700 and 1000 m	17800 - 46600	22	135 – 353

Table 4-2 **Overview of well test interference results.**

4.4 Calibration of dynamic model to summer injection test results

The interference test results showed that the pressure behaviour of BGM-5 could best be matched with a closed compartment model, having a non-sealing fault between BGM-6 and BGM-3 also another fault between BGM-1 and BGM-5. Some more evidence of the possible existence of faults in the Main block was found in the historical pressure data. The P/Z plot was detrended to better see deviation from straight line behaviour, see Figure 4-10. In 1973, 1997 and 1990 well testing of BGM-3, BGM-6 and BGM-1, done at about the same moment in time, shows BGM-3 to consistently have pressures that are 2-3 bar higher than the other wells. The Eclipse model was therefore set up to check fault transmissibility and pressure behaviour of the Summer Injection Test.

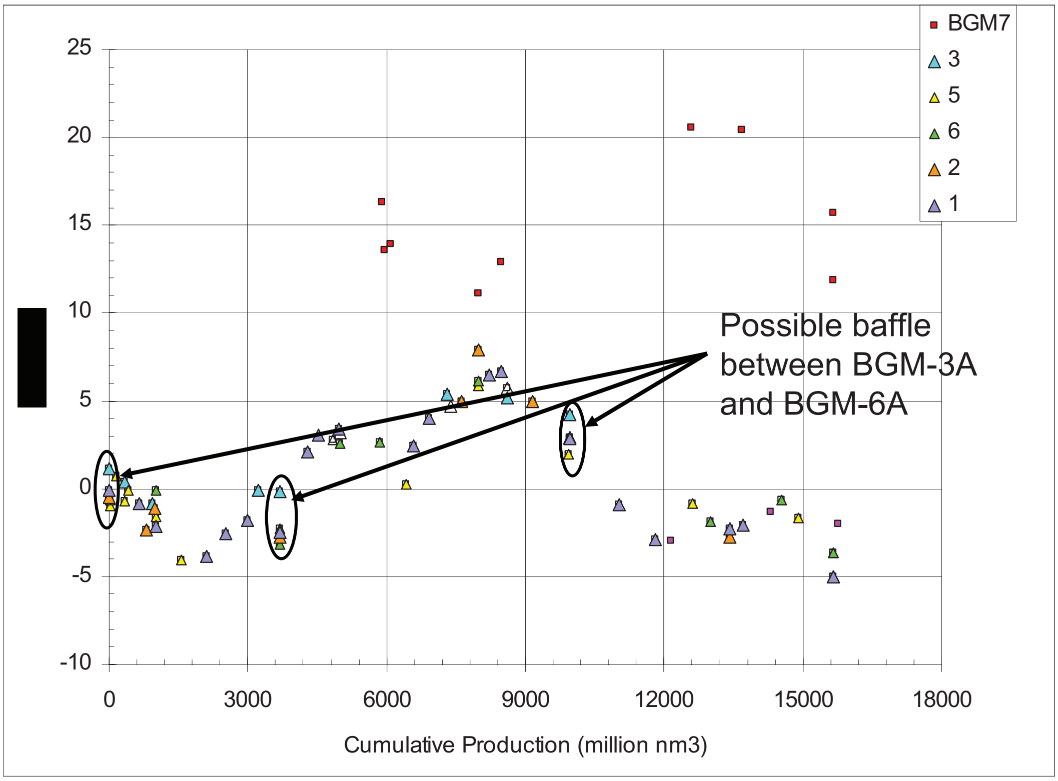

Figure 4-10 P/Z plot detrended with initial p/z of 249 bar and GIIP of 16500 Nm3 showing deviation from straight line behaviour. A possible baffle between BGM-3 and BGM-1 could explain higher pressures in BGM-3

The injection-test matched model shows that the pressure in BGM-6A drops 2 bar after injection, BGM-1 drops 1 bar after shut-in, BGM-5 and BGM-2 increase 1 bar, see Figure 4-11. Well BGM-3 shows little reaction, as does BGM-7. Note that none of these baffles was simulated with a threshold pressure; the model shows that the BGM-5 and BGM-6 blocks will be equalized up to 0.2 bar after 4 months at 12.4 bar. If the reservoir pressure in the field will not equalize totally in the next few months, a difference in transmissibility of the faults or a threshold pressure is needed.

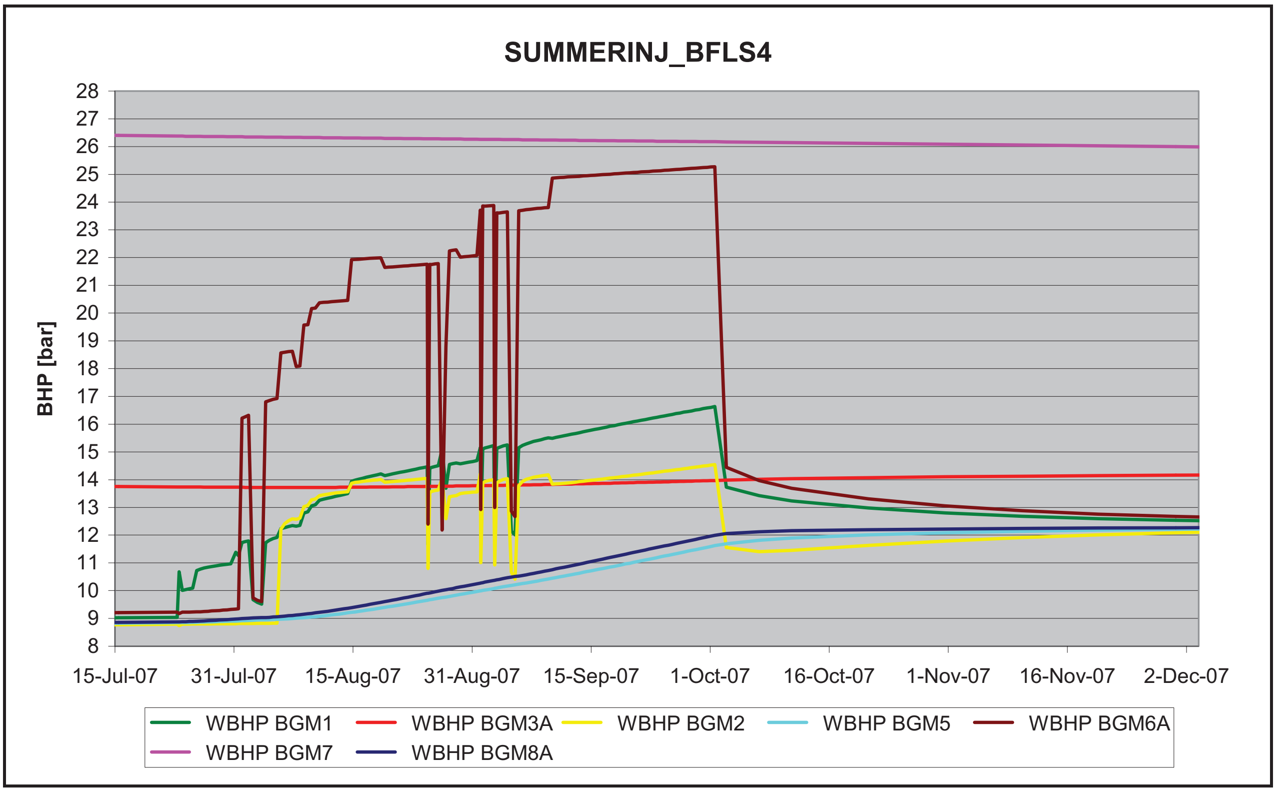

Figure 4-11 BHP pressures in dynamic model summer injection test

In Figure 4-12 the field data of wells BGM-5, BGM-6 and BGM-7 is plotted together with the modelled data. It can be seen that in the field, the delay in reaction of the wells is still greater than what was modelled. Figure 4-13 shows the compartmentalisation of the Main block as interpreted from the Summer Injection Test and checked in the dynamic model. The summer injection test model was then used to re-history match the production phase of Bergermeer.

Figure 4-14 shows a rerun of the production history pressure match. The baffles from the summer injection test have improved the history match of the field. The difference in pressure between the main compartment (represented by BGM-1) and Block II with BGM-7 has increased, while not changing the volume distribution. While the average pressure in the main block has decreased with less than 1 bar compared to the previous HM, the BHP difference is greater for the individual wells. BGM-3 shows a maximum pressure-increase of 6 bar in 1990 in the new history match.

The contact match changes (Figure 4-17) are very minor; they will be discussed in the next section.

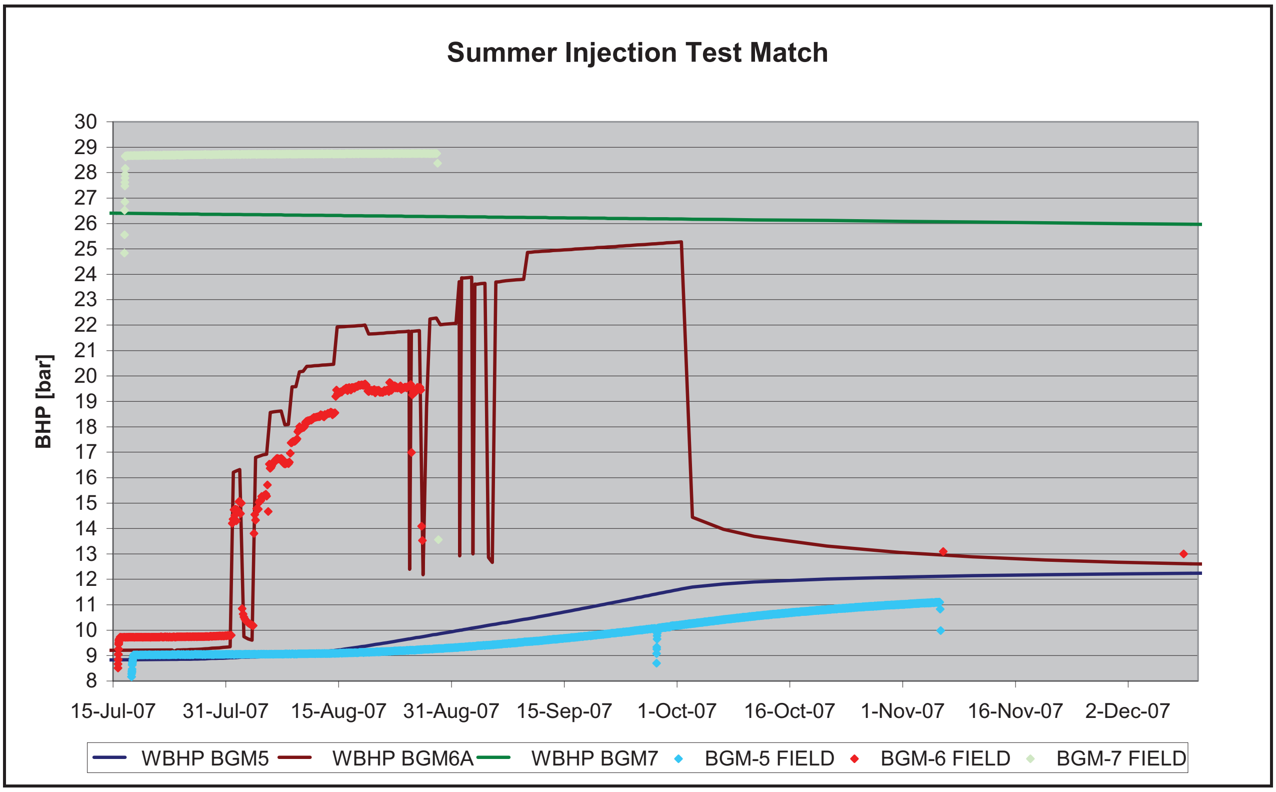

Figure 4-12 Pressure match summer injection test before, during and after injection. Continuous lines are from dynamic model (SUMMERINJ_BFLS4), the dots are field data points

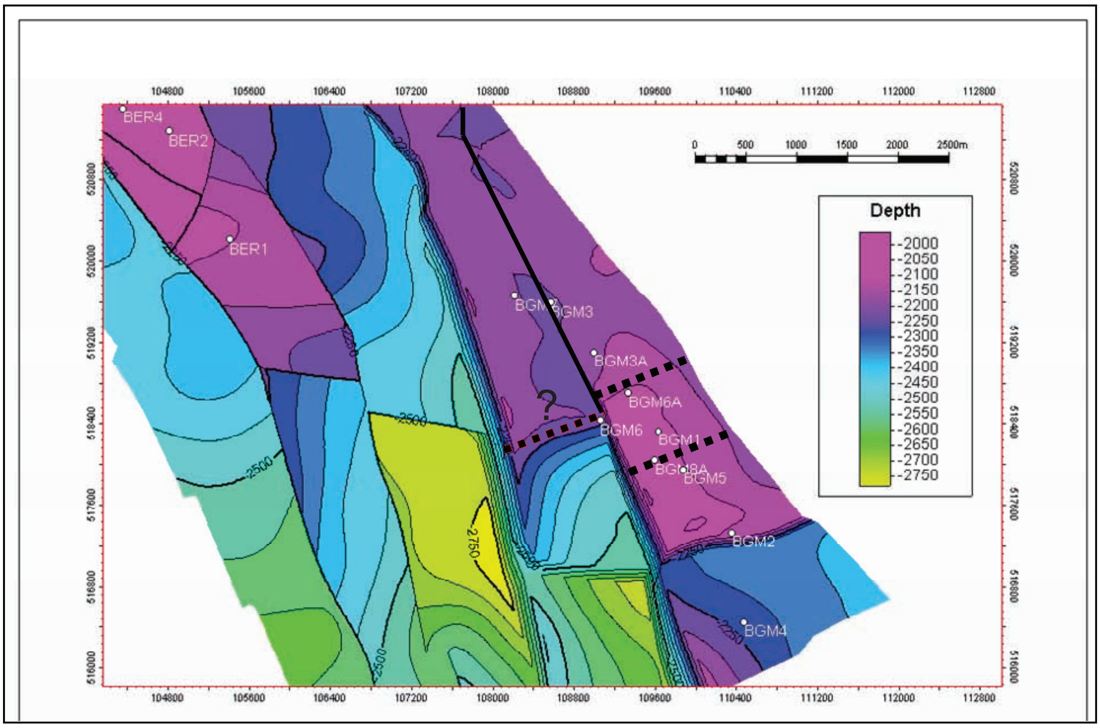

Figure 4-13 Baffles in main block as used in history match projected on top Rotliegendes map.

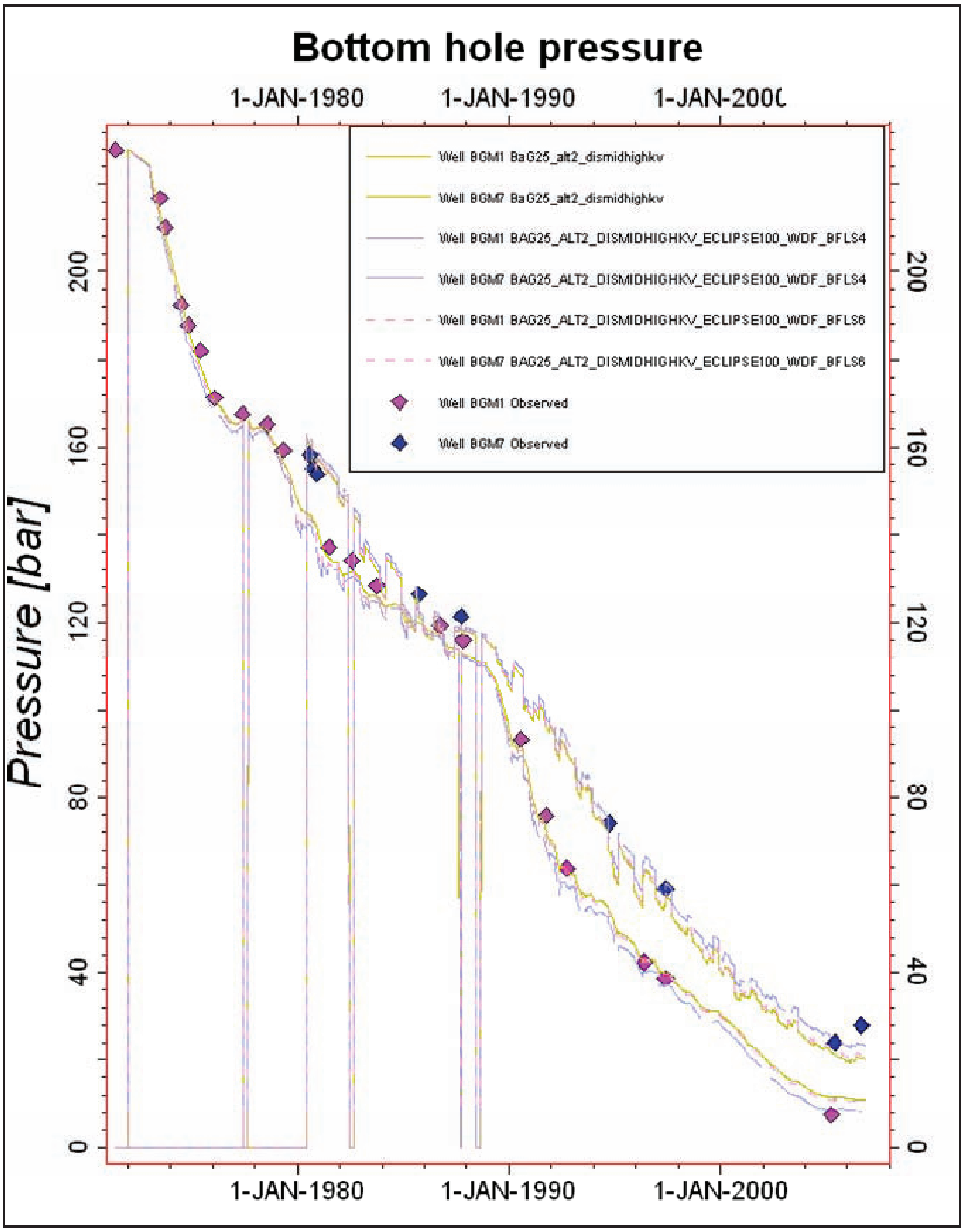

Figure 4-14 **Re-history match of Bergermeer production period, with baffles in main compartment as seen in summer injection test. Blue line is new HM, brown line is old HM. Purple diamonds are SBHP values BGM-1, blue diamonds are SBHP values BGM-7.**

4.5 GWC movements summer injection test

The current reservoir model assumes no aquifer. The rise in GWC in BGM-1 is explained by a local rise of the GWC in the most productive (southern) part of the field, and not by a field-wide rise of the GWC level. The model predicts tilting in Block-I and a general difference in GWC between Block-I and Block-II.

The position of the present GWC as predicted by the model is given in Figure 4-15. According to the results, the well BGM-3 has the largest difference in GWC compared to well BGM-1. The difference could be confirmed by an actual measurement in BGM-3, supporting the non-aquifer tilting GWC model. The well is however not accessible to the accepted depth of the GWC. Measurement of the GWC in BGM-7 could confirm the model, however also BGM-7 is not accessible due to sand fill and fish in the hole.

Figure 4-16 shows the modelled GWC movement during the summer injection test. The dotted lines represent the GWC during the end of the production period in 2006, the continuous lines represent the GWC modelled during Summer Injection. Previous producers BGM-1 and BGM-7 show a step of 1m, resp. 3m downward at 1.1.2007. This represents the collapsing of the cone after shut-in of the wells in the model. During the Summer Injection Test, the GWC in BGM-1 is pushed almost 5 m downwards, at shut-in the GWC rises again, stabilising at about 1.5 m lower than before the test. In well BGM-3A, the GWC drops ca 0.5 m and the ca 0.2m fall in GWC of BGM-7 is only due to internal pressure equilibration.

As discussed above, the dynamic model was adapted based on the findings from the summer test. Figure 4-17 shows the water contact movements in the new History Match. These are, like the pressure match discussed above, affected in minor ways only compared to the previous History Match.

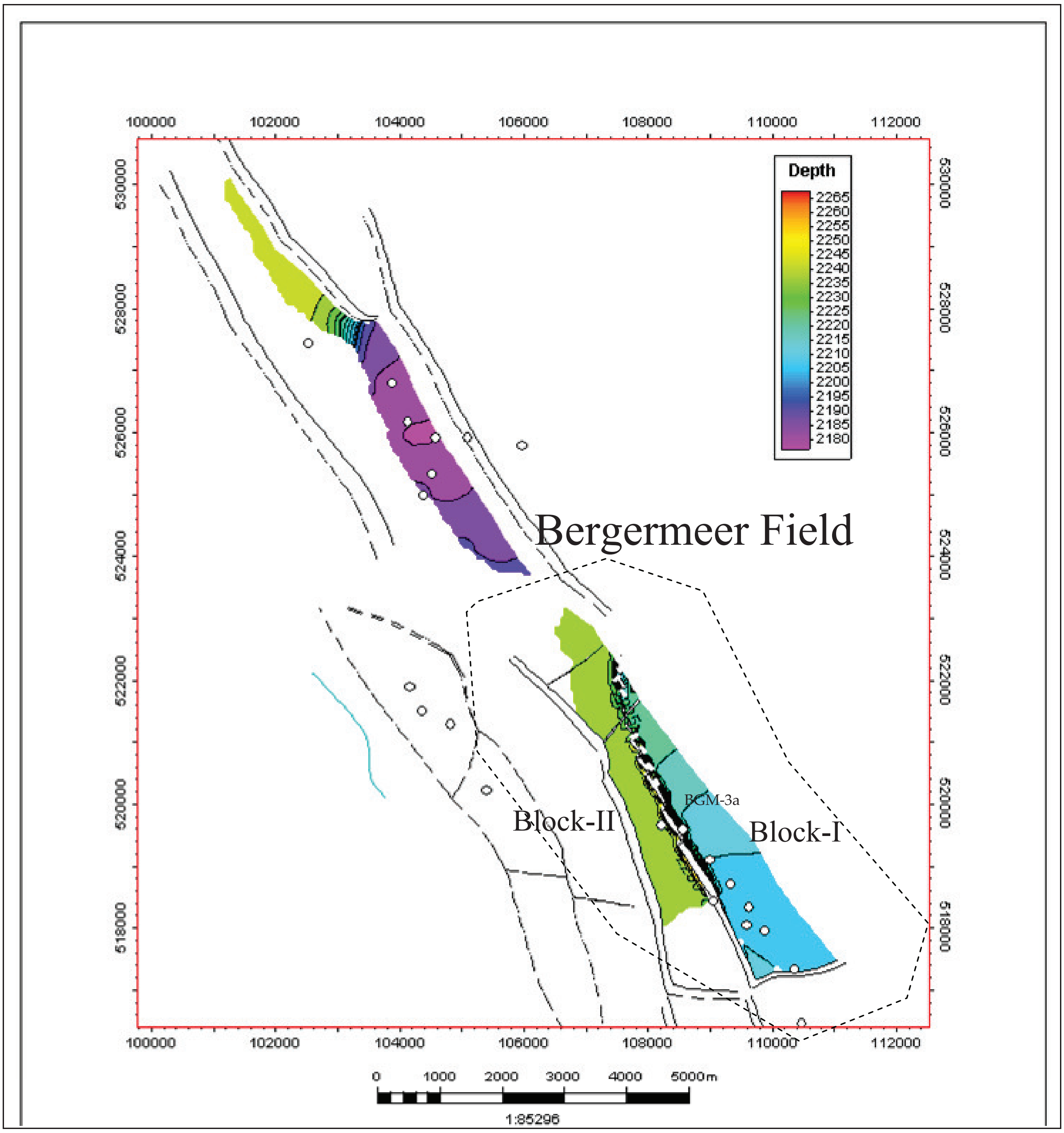

Figure 4-15 **Depth of GWC at 1.1.2007 before start of summer injection test, as forecasted by the dynamic reservoir model**

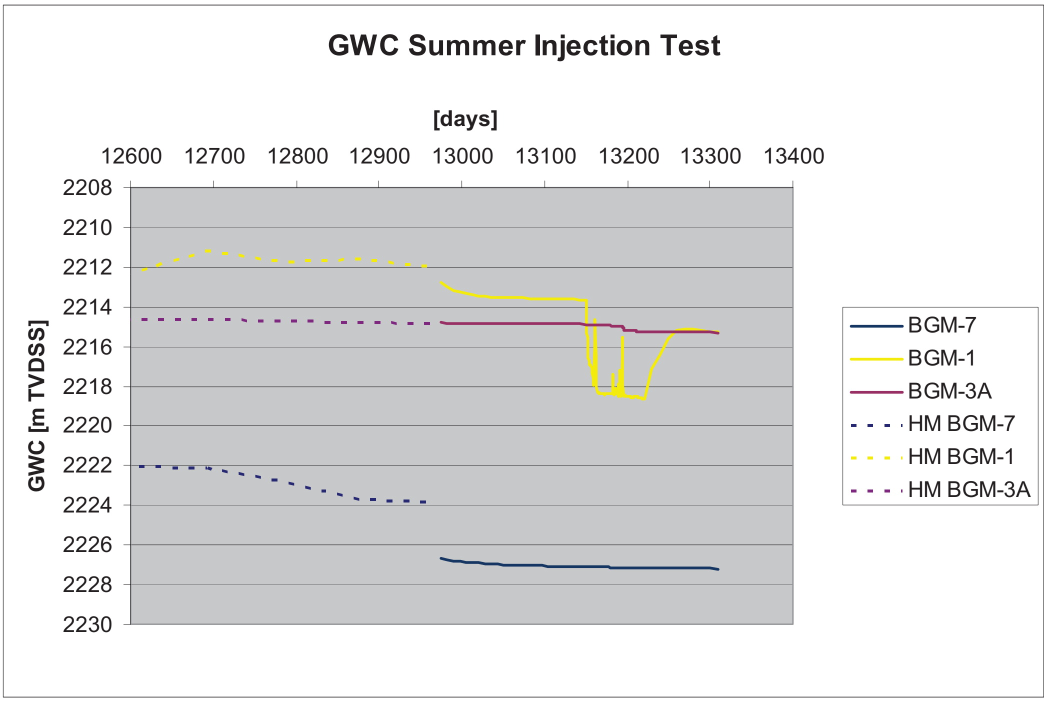

Figure 4-16 Depth of GWC as predicted by the dynamic reservoir model over the summer injection test.

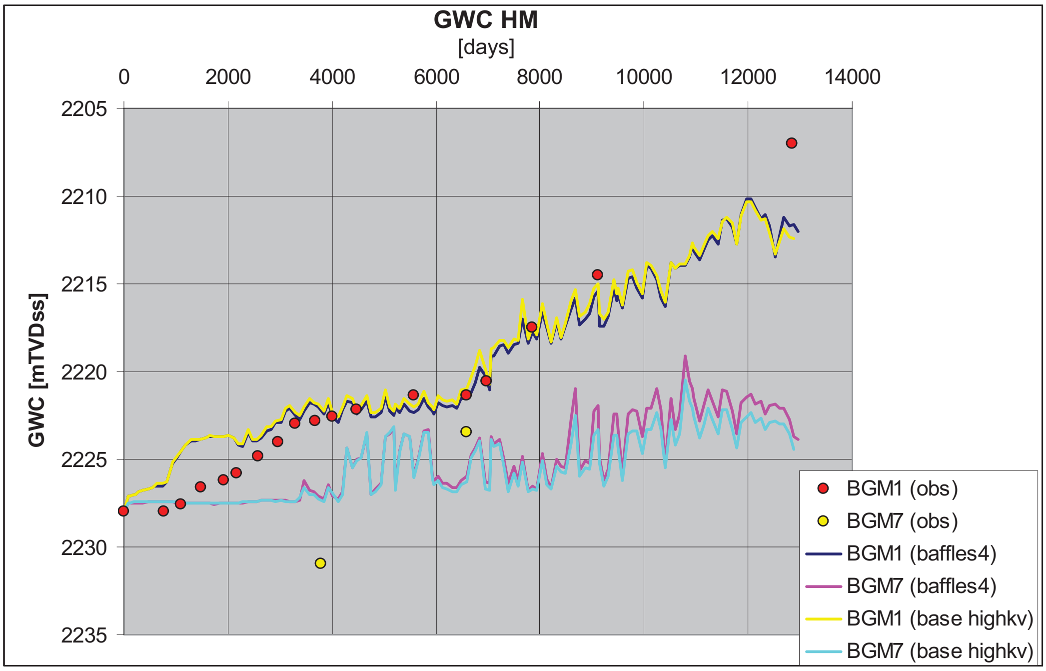

Figure 4-17 GWC in BGM-1 and BGM-7 during re-HM of production period. The updated dynamic reservoir model (DISMIDHIGHKV_baffles4) has the additional baffles interpreted from the injection test. Note that this model is the high-case model in Table 2-3 and Table 5-2.

5 UGS forecasting

5.1 Development scenarios

The UGS storage specifications for the base case were described in section 2.2. Additionally a low and a high case for total field deliverability and working volume were defined. A strong limitation of the possible development scenarios is caused by the pressure-constraint for the main fault in the field. In order to reduce the risk of seismic reactivation, the target pressure difference over the fault in the UGS phase is 0 bar, while the difference should not be higher than what was seen historically (dP max = 20 bar). Consequently, the drilling of an extra well in Block-II should be balanced by an extra 3 to 4 wells in the main block. Limiting the tubing size to 7 5/8", the chosen offtake scenarios can thus be described by the number of wells that are planned in block-II (BGM-7). The development scenarios can be summarised as:

[deleted text because of confidentiality]

Case	Nr. wells	Hor. wells Block-2	Vert. wells Main block	Hor. wells Main block
MEDIUM	XXX	XXX	XXX	XXX
LARGE	XXX	XXX	XXX	XXX
XLARGE	XXX	XXX	XXX	XXX

Table 5-1 Offtake scenarios MID, LARGE, XLARGE field development, based on geological model DISMIDHIGHKV. [deleted text because of confidentiality]

The skin assumptions were calibrated on measured data, as discussed in the chapter 3. No non-Darcy inter-gridblock flow was simulated.

The skin assumptions for the base case are:

- Skin: 0
- Non-Darcy skin: 2e-5 $[m^3/d]^{-1}$

The mechanical skin value is based on welltest results (section 2.4). It is assumed that a modern well will be drilled with less skin than the existing wells in Bergermeer (values between -3 and 10). Future well-modelling will investigate the effects of gravel-packs etc. The non-Darcy skin was made to match BGM-1 isochronal test-data results (section 3.3). In the model it was included as a correlation between porosity, permeability and wellbore radius.

5.2 Subsurface realisations

The BELL subsurface scenario's, needed to better match the well-test results in the north (BGM-3A) and west (BGM-7) of the field, are already discussed in section 2.5 (History Matching Alternates). Out of the alternative permeability models, three subsurface scenarios were selected, as discussed in section 2.3, and again specified in Table 5-2 below.

Case	Name	PERM MULTX (top-mid)	Perm.av. BGM-7	Perm.BGM-1
LOW	DISMIDHIGHKV_BELL_033	0.17 – 0.67	85	500
MID	DISMIDHIGHKV_BELL_050	0.25 – 1.00	125	750
HIGH	DISMIDHIGHKV	1.00 – 1.00	300	800

Table 5-2 Subsurface realizations LOW, MID, HIGH case, showing permeability multipliers and averages in the gas-zone for wells BGM-1 and BGM-7 (see [deleted text because of confidentiality])

5.3 Well planning

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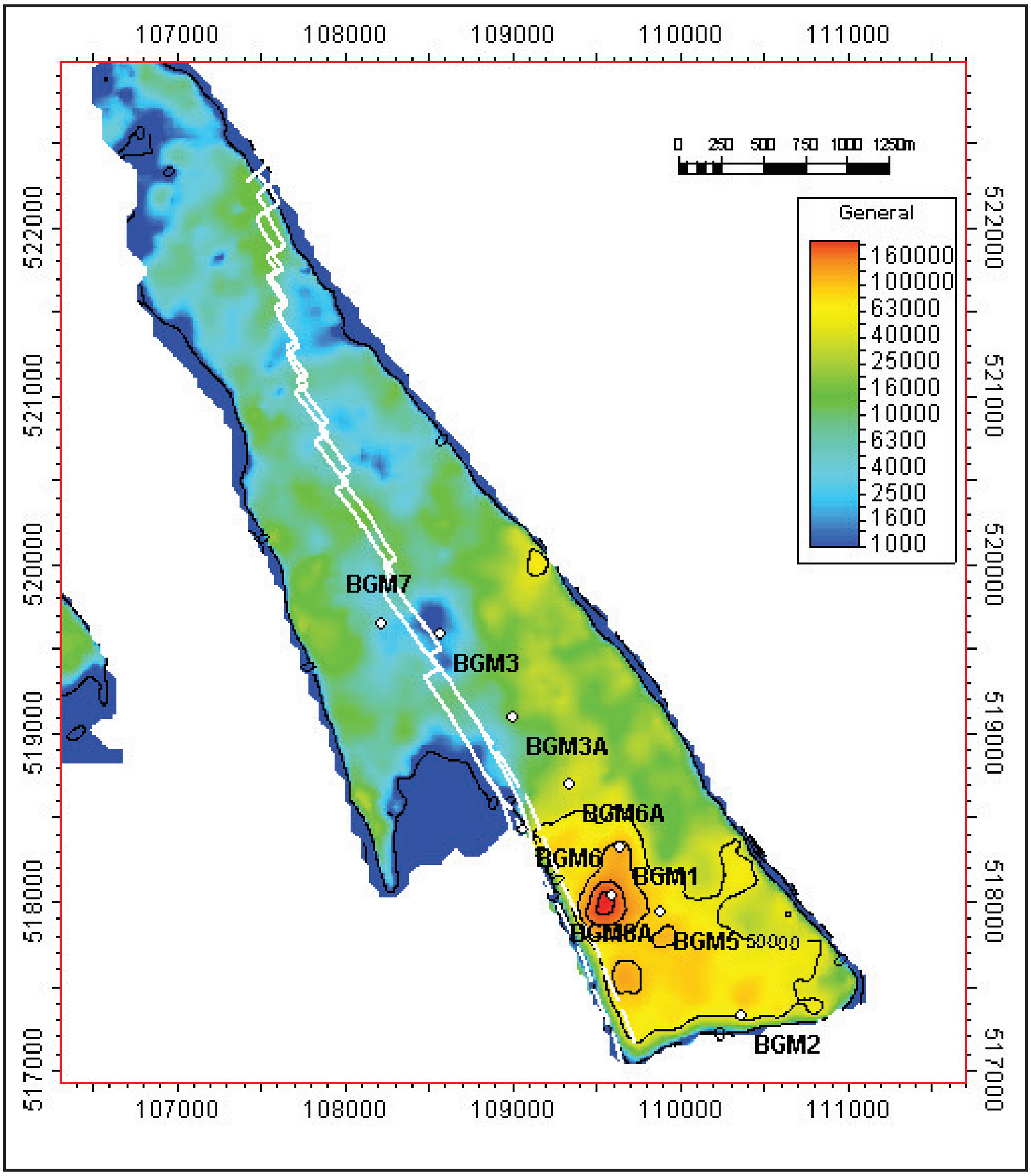

Figure 5-1 **KH distribution in the BGM field [mDarcy*m]. The data plotted is based on the 'DISMID_HIGHKV_BELL_050' realization. The value is the average permeability over the Rotliegend above the original GWC, multiplied by the distance of the original GWC to the top Rotliegend. (Cf. the very similar plot for the 'CONTMID' realization in [1]). The colour scale used is logarithmic.**

Figure 5-2 [deleted text because of confidentiality]

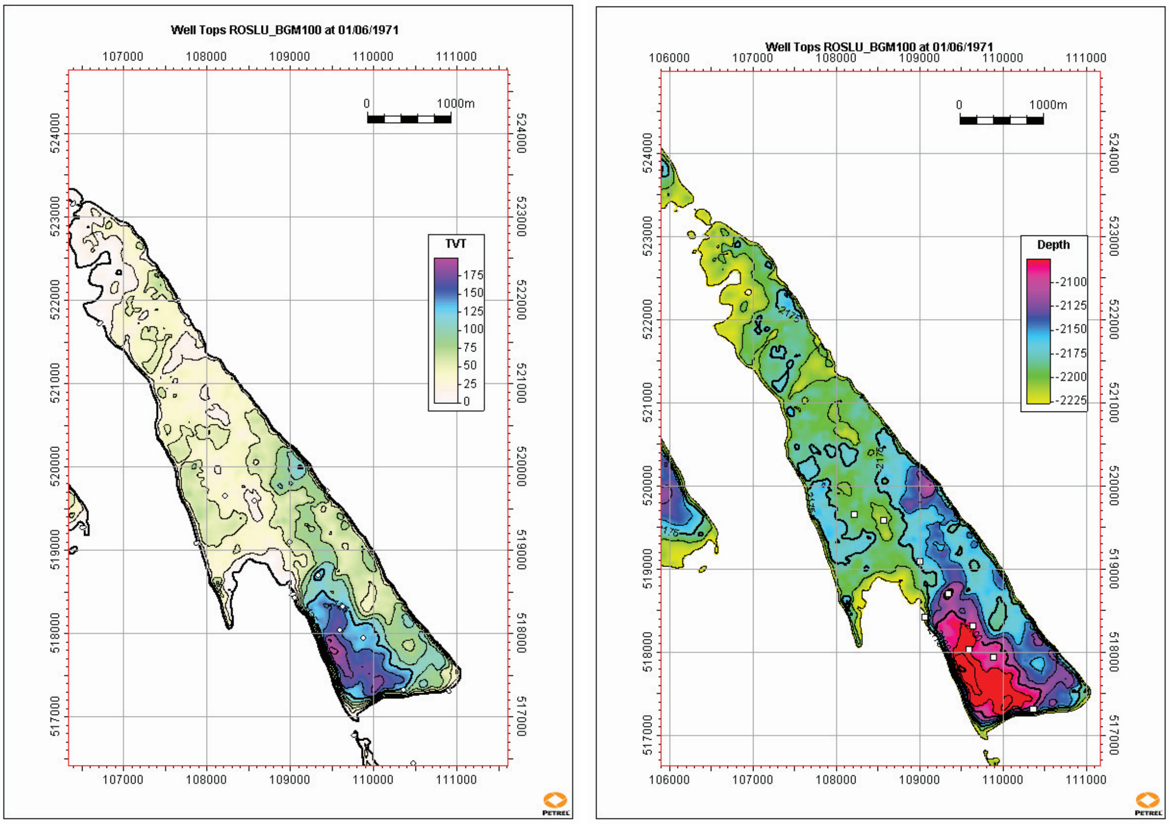

Figure 5-3 Net reservoir height map between top Rotliegend and original GWC at 2227 m (left) and depth of top Rotliegend (colour scale limited to above 2227 m; right)

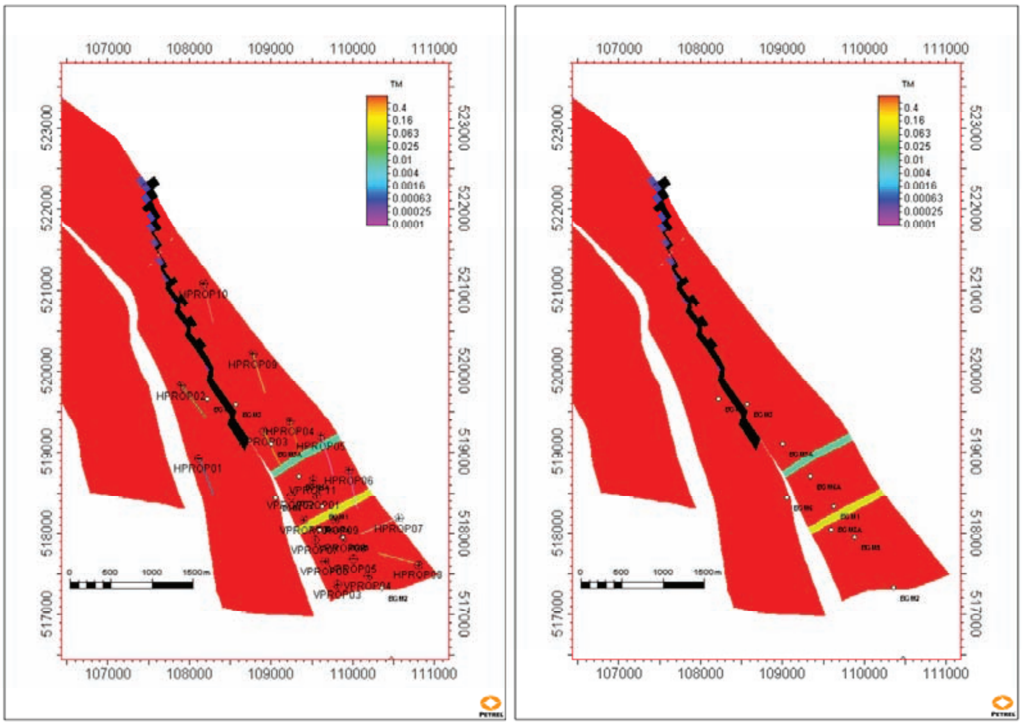

Figure 5-4 Position of dividing fault between Main and BGM-7 compartment (blue) and the baffles in Main, north of BGM-6 (green) and south of BGM-1 (yellow), as discussed in chapter 4. New wells are shown in the left graph, existing wells in the right graph.

5.4 Forecast results model DISMIDHIGHKV

Forecasts were run for three different field offtake rates and three different geological models. Results of the BELL_050 (base case geological model) and BELL_033 (low case) model are presented in

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The wells in BGM-7 were needed to balance the pressures between the two compartments. An overview of the forecast results is presented in Table 5-3.

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BERGERMEER	M	L	XL
Cushion gas [Bscm]	XXX	XXX	XXX
Working gas [Bscm]	XXX	XXX	XXX
Av. prod. / inj. rate [MMsm3/d]	XXX	XXX	XXX
Pres full [bar]	XXX	XXX	XXX
Pres empty [bar]	XXX	XXX	XXX
Wells block I / II	XXX	XXX	XXX
Total nr. of wells	XXX	XXX	XXX

Table 5-3 Bergermeer UGS forecast results for Mid, Large and XLarge offtake scenarios, all with DISMIDKIHGKV geological model

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Figure 5-5 and Figure 5-6 compare the UGS reservoir pressure behaviour of the initial forecast runs with the final ones. It can be seen that the Main and BGM-7 compartments were re-pressurized at different rates. The BGM-7 block had less wells drilled into it and was considered a loss for the Main UGS-compartment. The maximum pressure difference over the fault was 75 bar at the first full cycle, now it is ca 2 bar. The final UGS cases are presented in Figure 5-7 and Figure 5-8. They show that with more wells in BGM-7, the difference in reservoir pressure between the Main and BGM-7 compartments is lowered steadily over time. During the cycles a maximum pressure difference of 2 bar over the fault is attained.

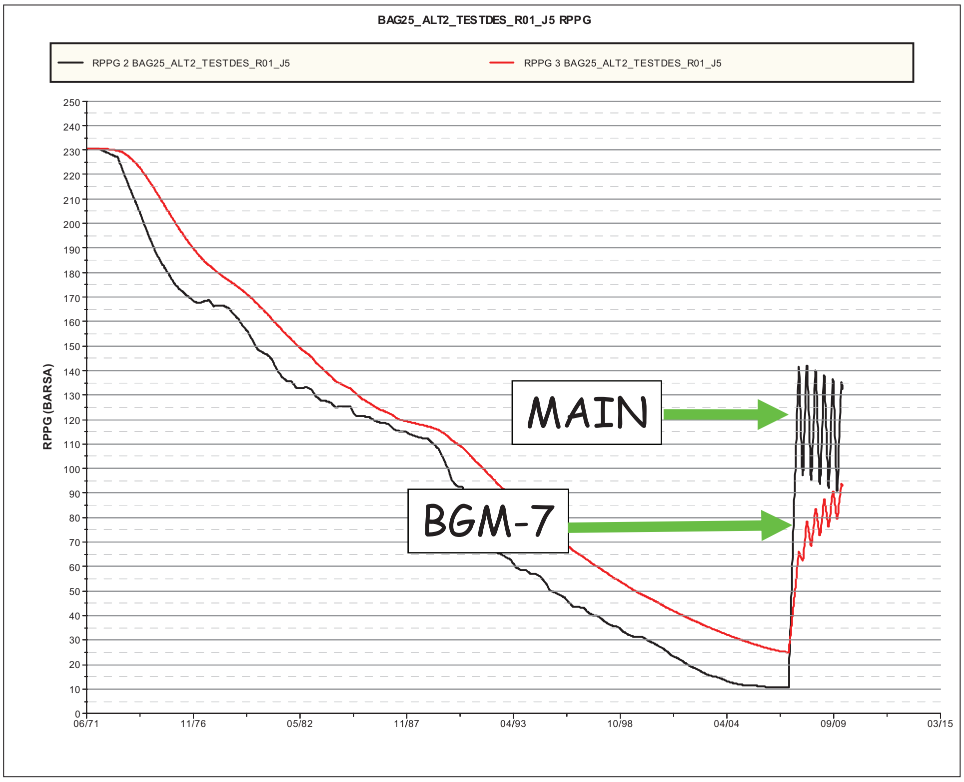

Figure 5-5 **UGS pressure behaviour BGM-7 and Main blocks in old runs, maximum dP 75 barover the fault, 10-20 cycles needed to equalize the two blocks, model DISMIDHIGHKV.**

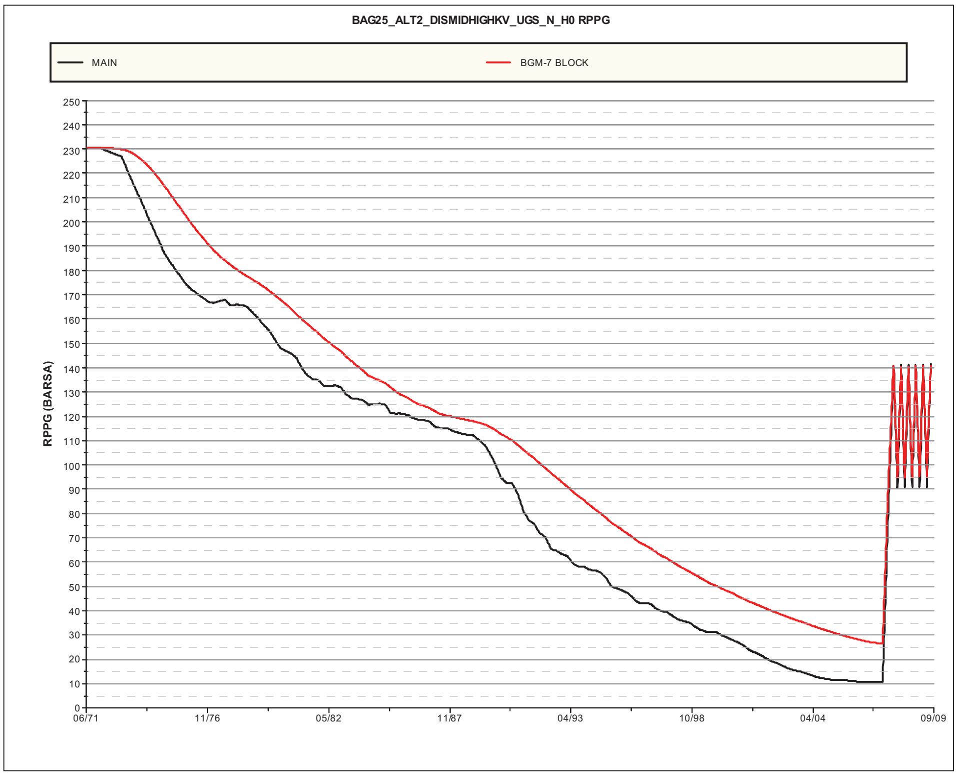

Figure 5-6 **UGS pressure behaviour BGM-7 and Main blocks in new runs, maximum dP over the fault 2 bar (DISMIDHIGHKV).**

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Figure 5-7 [deleted text because of confidentiality]

[deleted text because of confidentiality]

Figure 5-8 [deleted text because of confidentiality]

5.4.1 Tubing size

Larger tubing sizes have two main advantages for future development. Firstly, the number of wells can be lowered and secondly, the drilling of horizontal wells in the Main block can be avoided. It was assumed that the increase in tubing size would only be possible for the vertical wells. The Large and X-Large cases were rerun with new lift-tables and different well-configurations, the reduction in the number of wells for 8 5/8” and 9 5/8” tubing is found in Table 5-4. Objective was to keep the UGS capacity at the same level. An overview of the well numbers for the forecast runs, including tubing size variations, is given in Table 5-4.

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Table 5-4 [deleted text because of confidentiality]

5.4.2 GWC

The GWC movement in the reservoir during the UGS-cycles could be followed by using a script that was written to make fictive RFT measurements. In three wells in the reservoir, BGM-1, BGM-3A and BGM-7, the GWC is monitored for the M, L and XL cases, see Figure 5-9, Figure 5-10 and Figure 5-11. The pressures and gas-rates at which the three cases operate are given in section 5.4. The contact movement has an amplitude of ca 6 meters for BGM-1and BGM-7 and 2 m for BGM-3A in the Medium case. The Large case has 4m for BGM-1 and BGM-3A in Main and 7 meters in BGM-7. The XL-case shows 3 m for BGM-1, 14m for BGM-3A and 10 m for BGM-7.

The figures show that contact movement decreases for BGM-1 from M to XL, while it increases for BGM-3A and BGM-7. This can explained by the fact that in the M case, no horizontal wells are used in the Main block, and the field capacity is based entirely on the vertical wells in the south. BGM-3A is close to new well H_03, while BGM-7 is closest to H_02.

Figure 5-12, Figure 5-13 and Figure 5-14 present plots of the GWC at the end of an injection period (left hand graphs) and a difference map between the GWC before and after the injection period (left hand plots). Especially in the region of northern wells HOR_12 in BGM-7 block and HOR_10 in MAIN, the GWC has moved up close to the well through coning. Here the top Rotliegend is lowest; resulting in a short distance of the horizontal well to the GWC and a low reservoir permeability.

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Figure 5-9 GWC movement DISMIDHIGHKV, Medium case, 7 5/8” tbg, 15 wells

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Figure 5-10 GWC movement DISMIDHIGHKV, Large case, 7 5/8” tbg, 20 wells

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Figure 5-11 GWC movement DISMIDHIGHKV, Xtra-Large case, 7 5/8” tbg, 24 wells

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Figure 5-12 GWC maps DISMIDHIGHKV N31, Medium case, 7 5/8” tbg, 15 wells.

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Figure 5-13 GWC maps DISMIDHIGHKV N32, Large case, 7 5/8” tbg, 20 wells.

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Figure 5-14 GWC maps DISMIDHIGHKV N34, XLarge case, 7 5/8” tbg, 24 wells.

5.5 Forecast results BELL_050 and BELL_033 models

The lower permeabilities in the top reservoir-section of the field result in different pressure behaviour of the two compartments. The results of the BELL_050 run can be seen in Figure 5-16. It not only takes time for the two compartments to equilibrate (Figure 5-15), but in block-2 (BGM-7) there is also an internal reservoir pressure difference (Figure 5-16). This is caused by the fact that the wells are placed in the south of the block, while the block pressure represents the average reservoir pressure. Between HOR_1 in the south of block-2 and HOR_11 in the middle of it, the initial difference in reservoir pressure is 10 bar.

The BELL_033 run also shows internal reservoir pressure differences between wells HOR_01 and HOR_11. Probably because of an increased fault transmissibility set in the HM, the dP is less than for the BELL_050 run.

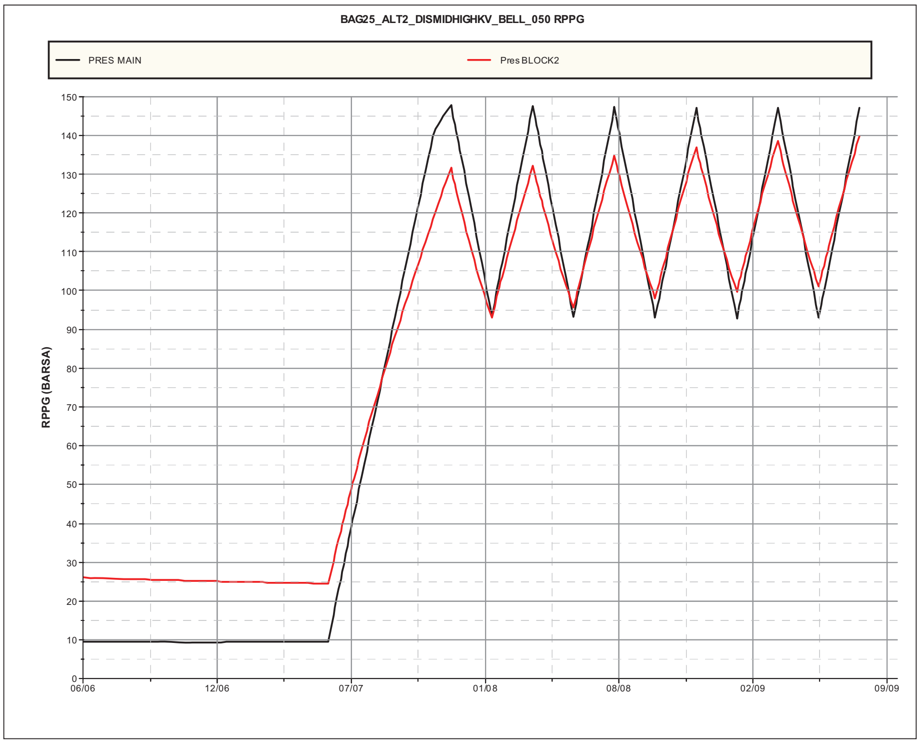


Figure 5-15 **Forecast sensitivity BELL_050. The Main block (black) and BGM-7 block (red) need time to equilibrate.**

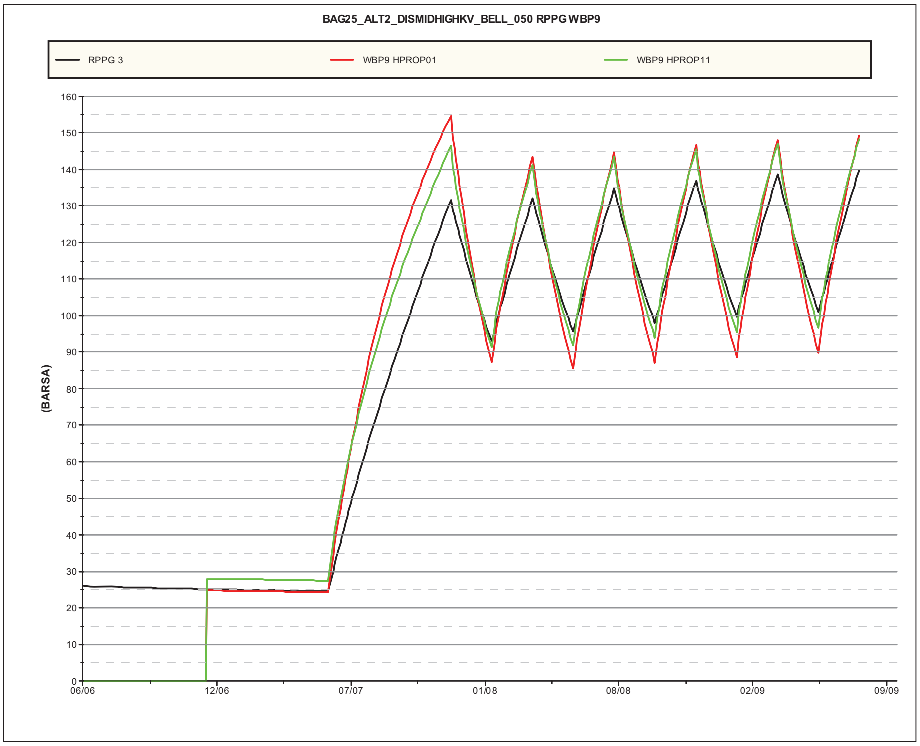


Figure 5-16 Forecast sensitivity BELL_050. Black is the reservoir pressure in block 2, red is P_res at HOR_01 and green is the P_res at HOR_11. They show that there is internal dP of 25 bar in block-2 at the start of the first cycle and between HOR_01 and HOR_11 dP_res is 10 bar.

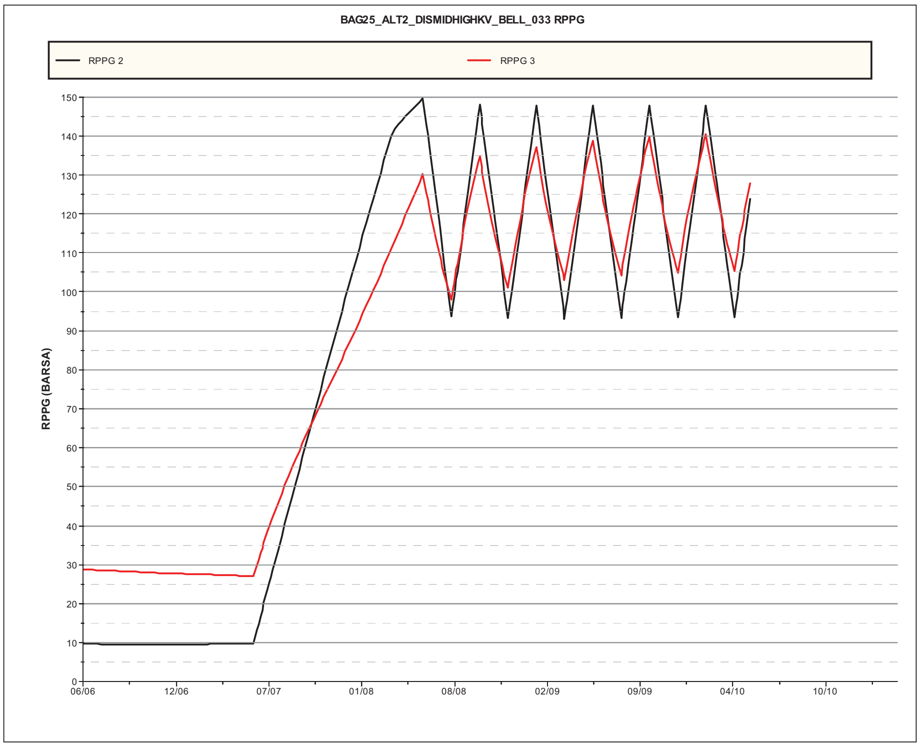


Figure 5-17 Forecast sensitivity BELL_033. The plot shows equilibration Main and BGM-7 blocks over time.

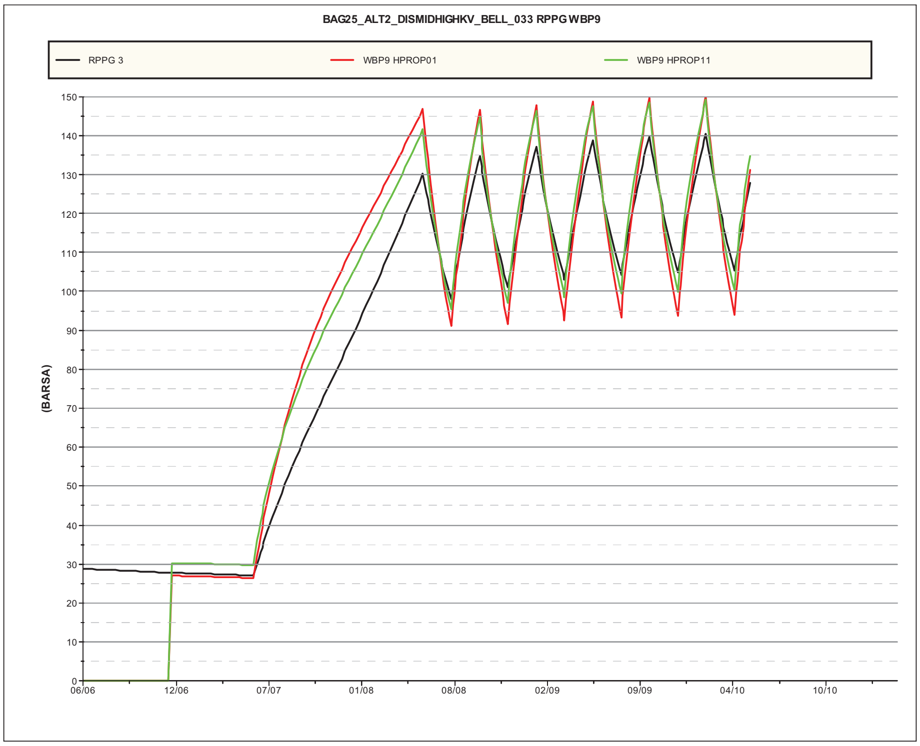


Figure 5-18 **Forecast sensitivity BELL_033. The plot shows internal dP of 17 bar in BGM-7 block at start of first cycle.**

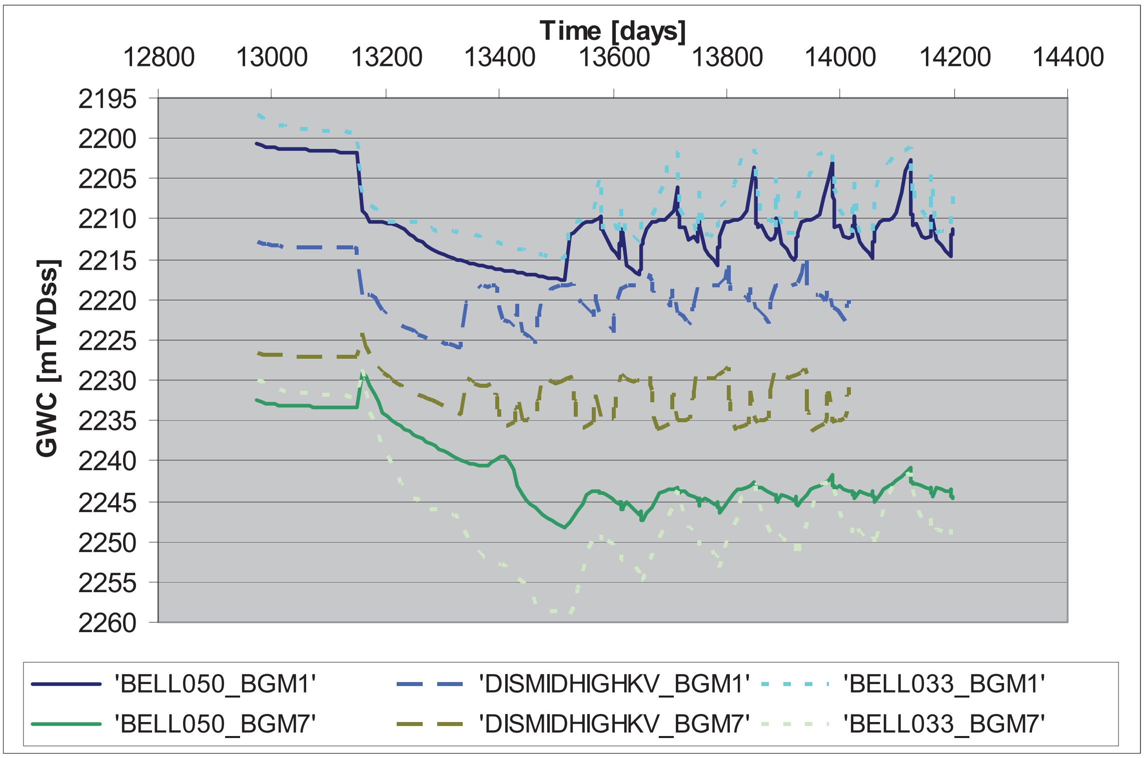


Figure 5-19 **GWC swings L758 (20 wells), for mid, high and low subsurface realisations.**

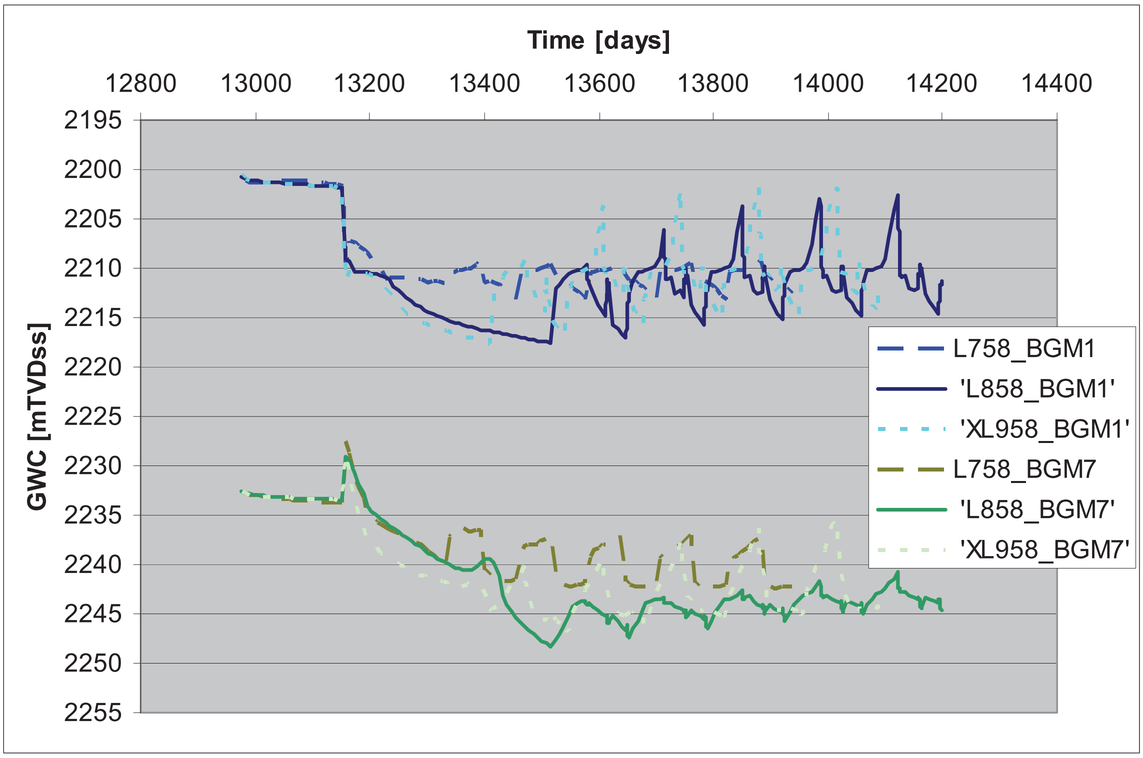


Figure 5-20 **GWC swings BELL_050 model. L758 has 15 wells in MAIN, 5 hor. in block 2 each 3.2 MMm3/d, L858 has 11 vert. in MAIN, 5 hor. in block-2 of 4.4 / 3.2 MMm3/d and XL958 has 11 vert., 6 hor wells of 4.9 / 3.0 MMm3/d. Maximum swings BGM-1 are 13 m, and 10 m in block 2 (BGM-7).**

5.6 Field performance curves

We need to deduce UGS field performance curves from the Eclipse results. This is done by running the UGS wells in the Eclipse model for short periods at various rates at three times: when the UGS is at its lower pressure, when it is at its higher pressure, and half-way in between. From these three rate "tests", THP, BHP and rate data are extracted. Then a parameterized fit linking THP to rate is obtained for the different classes of wells in the field. This parameterized fit can then be used to estimate field capacity curves at any pressure.

To obtain a convenient formula for this parameterization, the IPR formula was taken, already given in section 3.1, which describes the pressure drop in the near wellbore region,

$$P_{Res}^2 - BHP^2 = AQ + FQ^2$$

This is then combined with the equation used to describe the pressure drop in the tubing:

$$BHP^2 = B * THP^2 + CQ^2 .$$

Including the Darcy term (AQ) will complicate the calculation of Q from THP. However, it is typically only of importance at lower rates (<1 MMm3/d). As can be seen from a comparison (Figure 5-21), the Eclipse results can be fitted with an A=0 curve well enough for practical purposes. It should be noted that if we set A=0, the resulting fit parameters will differ slightly from the parameters where A is kept (of the order of a %

or less).

If we also take D=C+F, we get the following parametrization for the reservoir performance expressed at surface pressures

$$P_{\mathrm{Re}s}^2 = B * THP^2 + DQ^2 .$$

The equation has the shape of an ellipse, with the x- and y-axis crossings describing the shape. At Qmax (or AOF), the THP is 0 bar, so that we find for D:

$$D = \frac{P_{\mathrm{Re}s}^2}{{Q_{AOF}}^2} .$$

At maximum THP we find for B

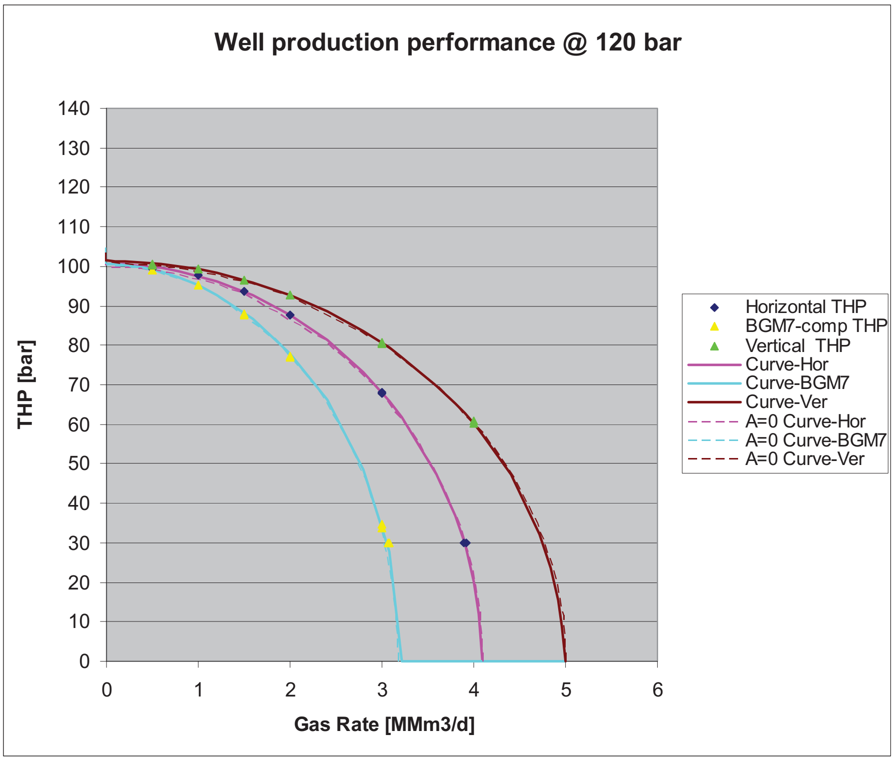
$$B = \frac{P_{\mathrm{Re}s}^2}{{THP_{MAX}}^2}$$

And the performance curves can thus be expressed by

$$\frac{Q_{AOF}}{THP_{\max}} \text{ and } \frac{THP_{\max}}{P_{\mathrm{Re}s}} .$$

The curves are subsequently determined for three groups in the reservoir, vertical wells in MAIN, horizontal wells in MAIN and horizontal wells in the BGM-7 block, see Figure 5-23. By multiplication of the performance of a representative well by the number of wells for the group, the field performance curves can then be constructed, see Figure 5-25.

Table 5-5, Table 5-6 and Table 5-7 give the field performance parameters of the high, mid and low case subsurface realisations for 7 5/8”, 8 5/8” and 9 5/8” tubings. In the next section, well performance differences within each group are discussed.



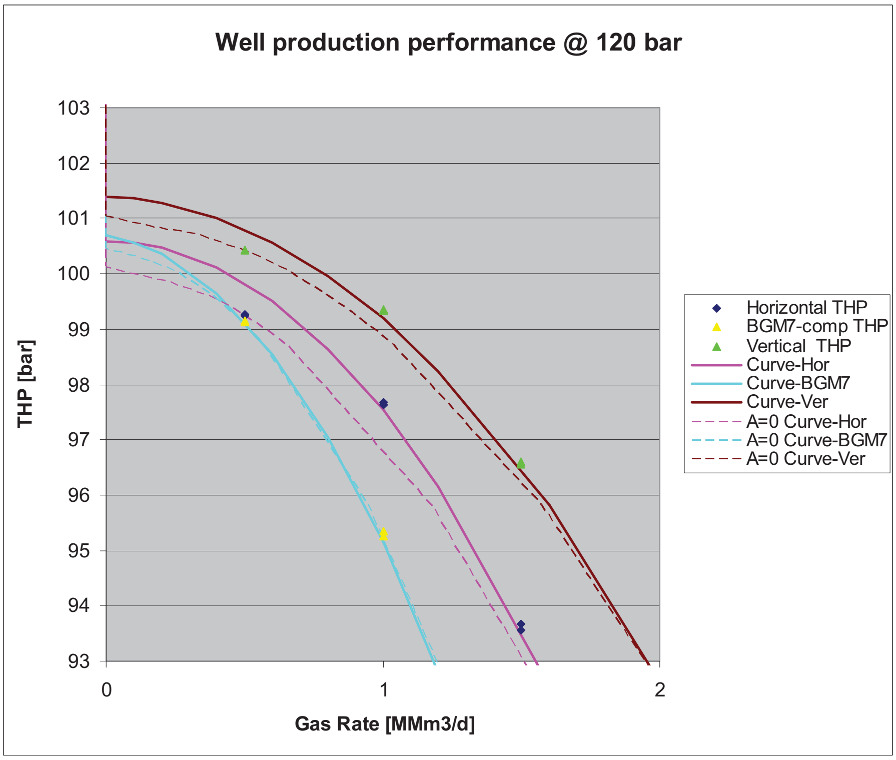


Figure 5-21 **Comparison of parameterized fits to the Eclipse THP/Rate data. Lines with Darcy term (full) and without Darcy term (dashed) are shown. The bottom plot is a zoom-in of the top plot, showing the difference is small, and only visible at low rates. It should be noted that the fit coefficients in the A=0 case are slightly different from the case where A is used.**
[The run used is the 'BELL_033_ALT_H06_H11' model, which has lowest permeability.]

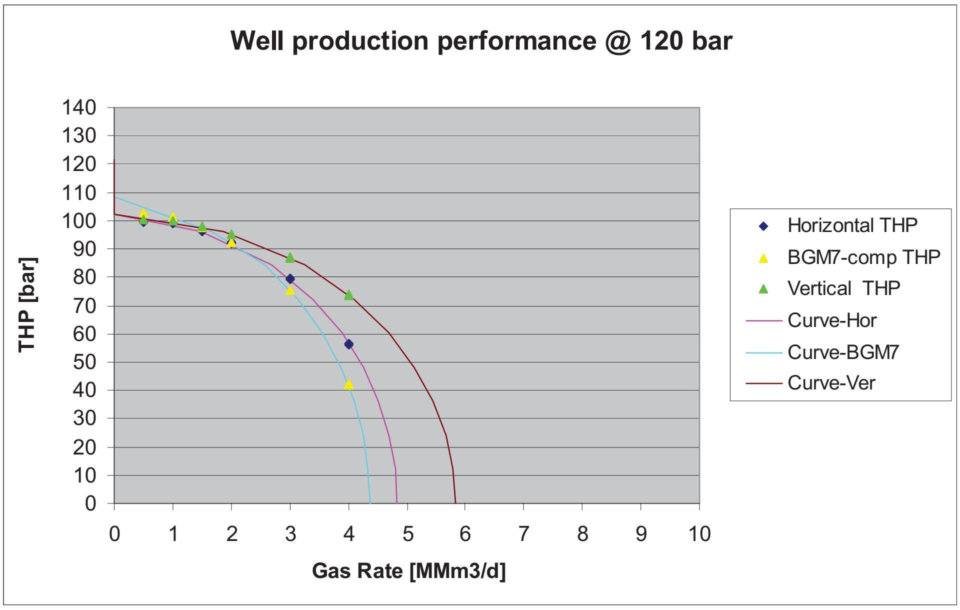


Figure 5-22 **Well production performance plot DISMIDHIGHKV_H06_H11, separate curves for vertical well (MAIN), horizontal well (MAIN) and horizontal well (BGM-7 block).**

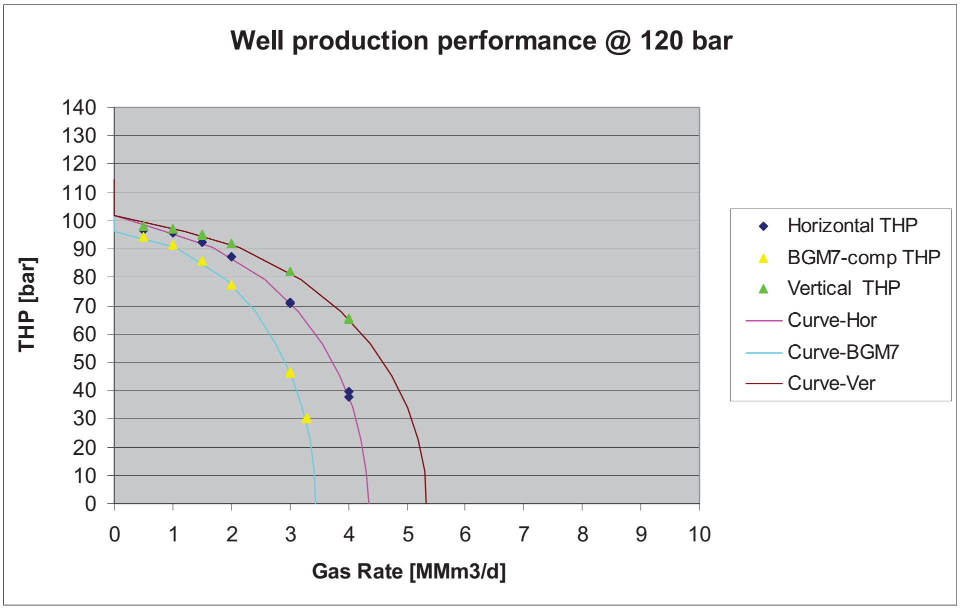


Figure 5-23 **Well injection performance plot DISMIDHIGHKV_BELL_050_ALT_H06_H11, separate curves for vertical well (MAIN), horizontal well (MAIN) and horizontal well (BGM-7 block).**

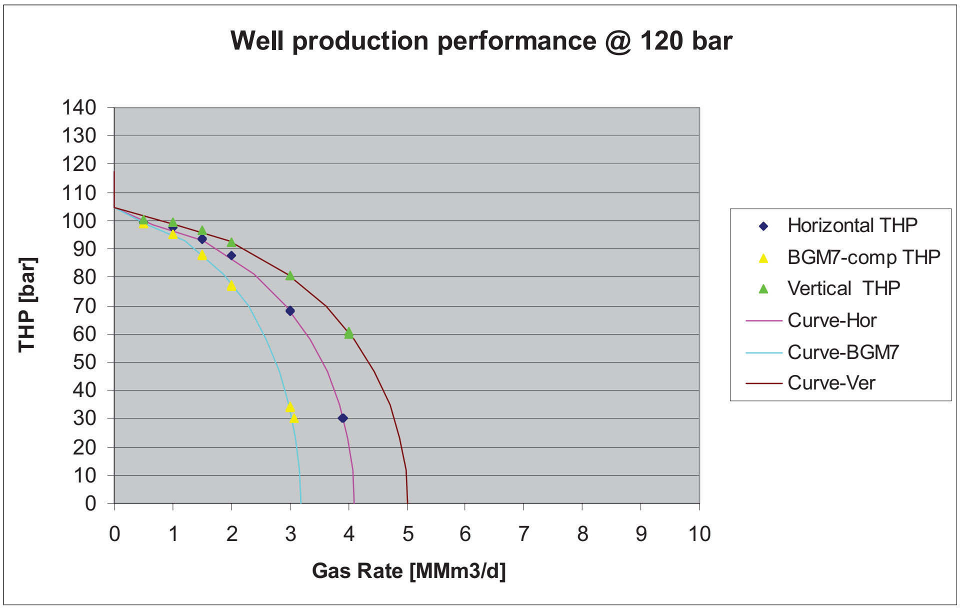


Figure 5-24 Well production performance plot DISMIDHIGHKV_BELL_033_ALT_H06_H11, separate curves for vertical well (MAIN), horizontal well (MAIN) and horizontal well (BGM-7 block).

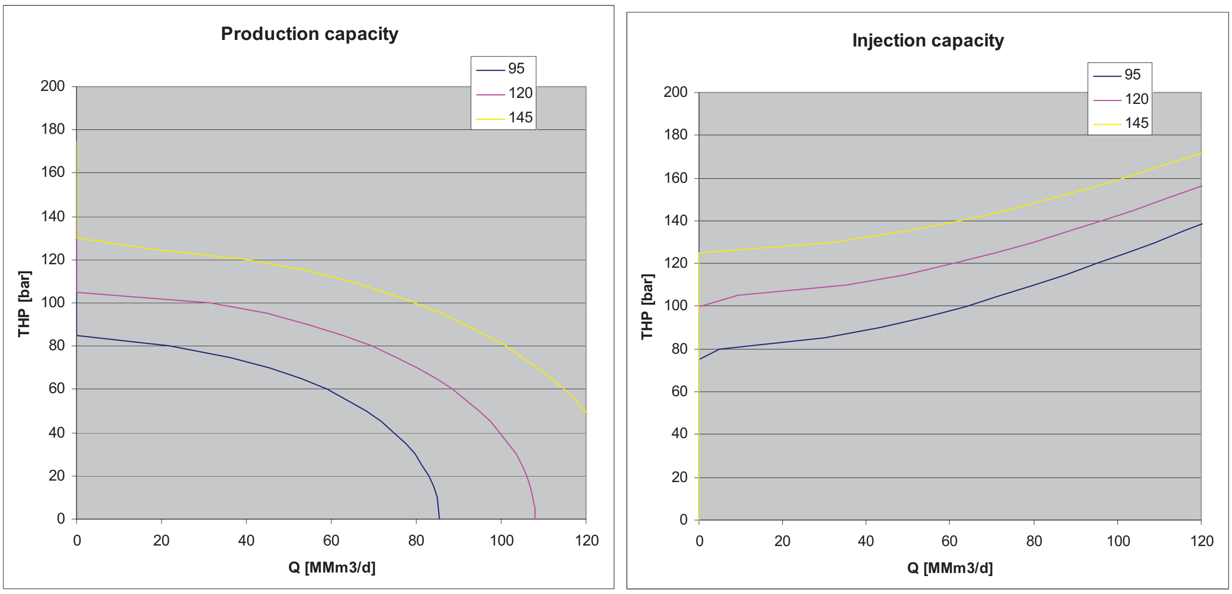


Figure 5-25 Field performance plots DISMIDHIGHKV_H06_H11 (high case), 20 wells 7 5/8", 5 HOR (BGM-7), 4 HOR (MAIN and 11 VERT (MAIN), at start, halfway at end of injection period.

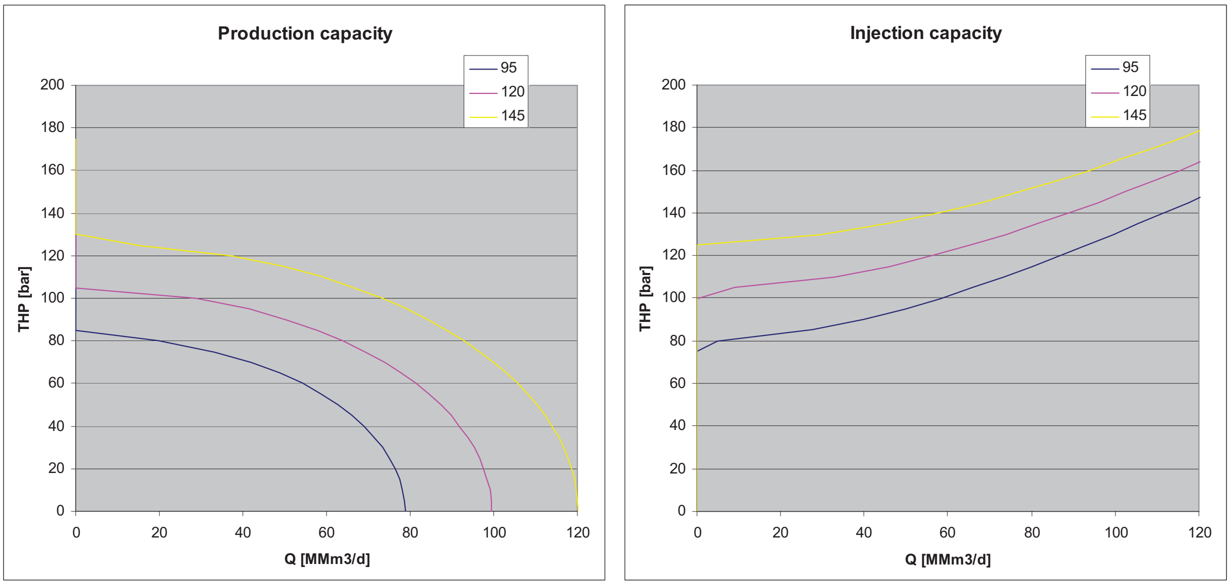


Figure 5-26 **Field performance plots DISMIDHIGHKV_BELL_050_ALT_H06_H11 (high case), 20 wells 7 5/8", 5 HOR (BGM-7), 4 HOR (MAIN and 11 VERT (MAIN), at start, halfway at end of injection period.**

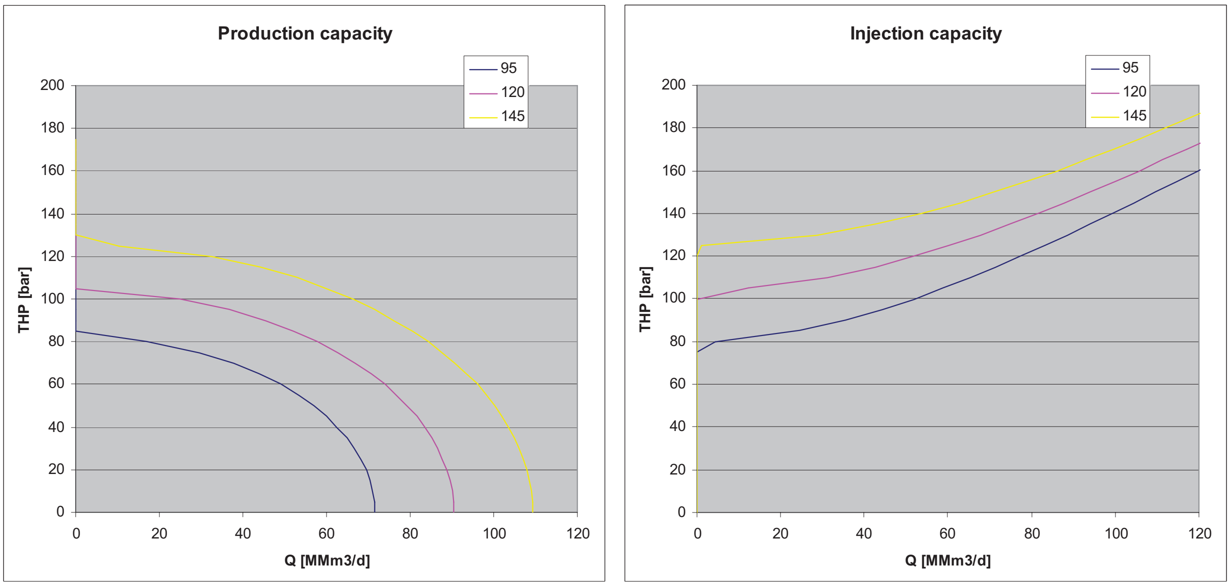


Figure 5-27 **Field performance plots DISMIDHIGHKV_BELL_033_ALT_H06_H11 (low case), 20 wells 7 5/8", 5 HOR (BGM-7), 4 HOR (MAIN and 11 VERT (MAIN), at start, halfway at end of injection period.**

	Prod						Inj					
	Hor/BGM1		Hor/BGM7		Ver/BGM1		Hor/BGM1		Hor/BGM7		Ver/BGM1	
Case	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre
7 5/8"	0.048	0.867	0.042	0.866	0.057	0.874	0.045	0.855	0.039	0.853	0.063	0.839
8 5/8"					0.075	0.872					0.064	0.862
9 5/8"					0.092	0.870					0.079	0.870

Table 5-5 **Field performance parameters HIGH CASE, pessimistic horizontal well position (DISMIDHIGHKV_H06_H11)**

Case	Prod Hor/BGM1 Qlim/THPli	THPlim/Pre	Hor/BGM7 Qlim/THPli	THPlim/Pre	Ver/BGM1 Qlim/THPli	THPlim/Pre	Inj Hor/BGM1 Qlim/THPli	THPlim/Pre	Hor/BGM7 Qlim/THPli	THPlim/Pre	Ver/BGM1 Qlim/THPli	THPlim/Pre
7 5/8"	0.044	0.867	0.036	0.862	0.054	0.874	0.041	0.854	0.033	0.850	0.058	0.838
8 5/8"					0.069	0.872					0.060	0.862
9 5/8"					0.082	0.870					0.066	0.857

Table 5-6 Field performance parameters BASE CASE, pessimistic horizontal well position (DISMIDHIGHKV_BELL_050_ALT_H06_H11)

Case	Prod Hor/BGM1 Qlim/THPli	THPlim/Pre	Hor/BGM7 Qlim/THPli	THPlim/Pre	Ver/BGM1 Qlim/THPli	THPlim/Pre	Inj Hor/BGM1 Qlim/THPli	THPlim/Pre	Hor/BGM7 Qlim/THPli	THPlim/Pre	Ver/BGM1 Qlim/THPli	THPlim/Pre
7 5/8"	0.041	0.861	0.032	0.864	0.050	0.869	0.037	0.853	0.028	0.848	0.052	0.838
8 5/8"					0.061	0.870					0.053	0.862
9 5/8"					0.070	0.869					0.062	0.870

Table 5-7 Field performance parameters of LOW CASE, pessimistic horizontal well position (DISMIDHIGHKV_BELL_033_ALT_H06_H11)

5.7 Forecast sensitivities

5.7.1 Influence of heterogeneity and well positioning

Due to the heterogeneity in the field with baffles in the Main block and decreasing reservoir height and permeability to the north, there is a pressure gradient in the field during the UGS cycles, see Figure 5-28. If we use vertical development well VERT_01 and horizontal wells HOR_01 (BGM-7) and HOR_05 (MAIN) to characterise the run, we get a more optimistic case (see Table 5-8). If we use the performance of wells HOR_11 (BGM-7) and HOR_06 (MAIN), the parameters turn out more pessimistic (Table 5-9). The pessimistic curves were taken for the low, mid, high realisations in order to be on the conservative side.

The left graph of Figure 5-33 shows that the pressures in HOR-5 reflect the overall reservoir pressure quite well. The performance curves that were based on HOR-5 to represent the horizontal wells in the Main block give a direct indication of reservoir pressure. The right graph shows that the red curve for HOR-1 in the BGM-7 is not straight. The P/Z behavior is influenced by the southerly position of HOR-1 in the block. The performance curves therefore underestimate real reservoir pressure at the end of the production cycle (empty UGS, low pressure) and overestimate the reservoir pressure at the end of injection (filled UGS, high pressure). This is however expected to actually take place, as the wells will be drilled close to the surface facility above BGM-1; the volume in the far north of the block is not well connected to the wells at UGS timescales because of its distance. Since the historical production progressed at far lower rates than is planned for the UGS, this effect is poorly constrained by the historical pressure behaviour.

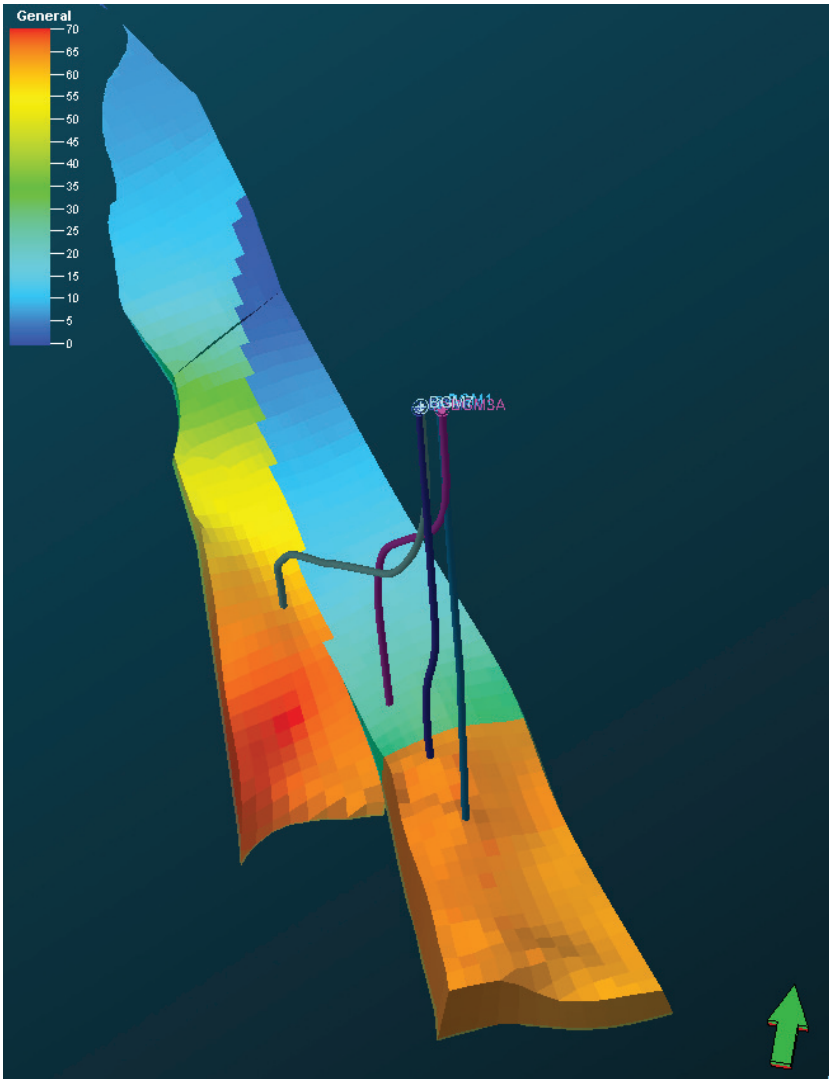


Figure 5-28 **Pressure difference between UGS 'full' at 145 bar and 'empty' at 95 bar. Run DISMIDHIGHKV_WDF_BFLS4, Large case, 20 wells all 7 5/8". Well shown from north to south are BGM-7, BGM-3A, BGM-6A and BGM-1.**

Case	Prod						Inj					
	Hor/BGM1		Hor/BGM7		Ver/BGM1		Hor/BGM1		Hor/BGM7		Ver/BGM1	
	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pres
7 5/8"	0.051	0.869	0.046	0.867	0.053	0.874	0.048	0.856	0.044	0.867	0.051	0.875
8 5/8"	0.080	0.866	0.063	0.865	0.072	0.872	0.071	0.864	0.057	0.865	0.066	0.873
9 5/8"	0.104	0.867	0.075	0.863	0.085	0.870	0.084	0.861	0.063	0.860	0.074	0.870

Table 5-8 **Field performance parameters, high case run sensitivity (DISMIDHIGHKV_H05_H01), optimistic horizontal well position, H05 for MAIN and HOR01 for BGM-7.**

Case	Prod						Inj					
	Hor/BGM1		Hor/BGM7		Ver/BGM1		Hor/BGM1		Hor/BGM7		Ver/BGM1	
	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre	Qlim/THPli	THPlim/Pre
7 5/8"	0.048	0.867	0.042	0.866	0.057	0.874	0.045	0.855	0.039	0.853	0.063	0.839
8 5/8"			0.043	0.866	0.075	0.872			0.040	0.854	0.064	0.862
9 5/8"			0.044	0.866	0.092	0.870			0.041	0.854	0.079	0.870

Table 5-9 **Field performance parameters, high case run sensitivity (DISMIDHIGHKV_H06_H11), pessimistic horizontal well position H06 for MAIN and H11 for BGM-7**

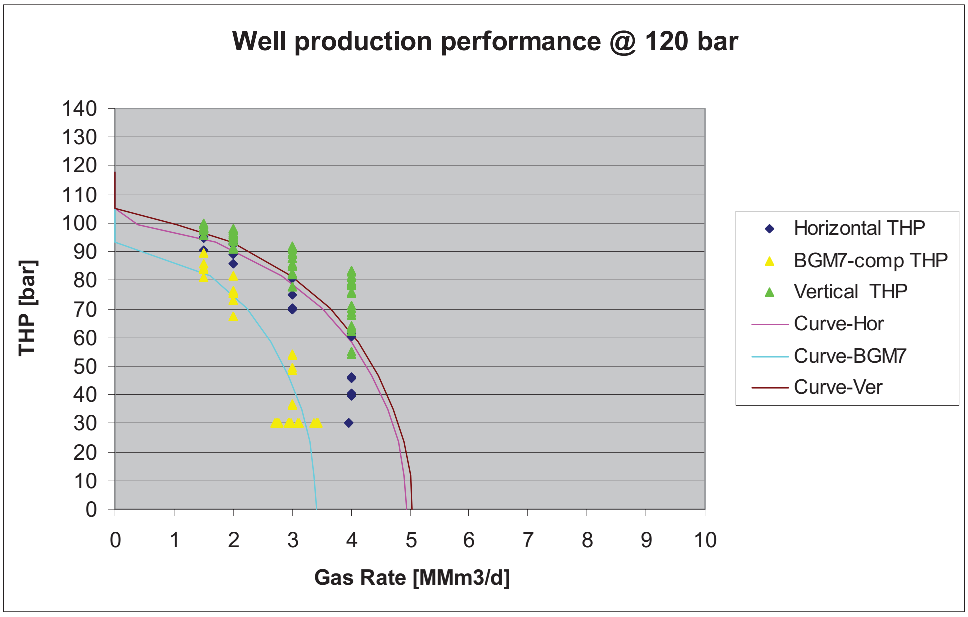


Figure 5-29 **Spread in well-performance in low subsurface realisation (BELL_033_ALT_H05_H01). The plot displays optimistic performance of wells V_01, H_05 (MAIN) and H01 (BGM-7).**

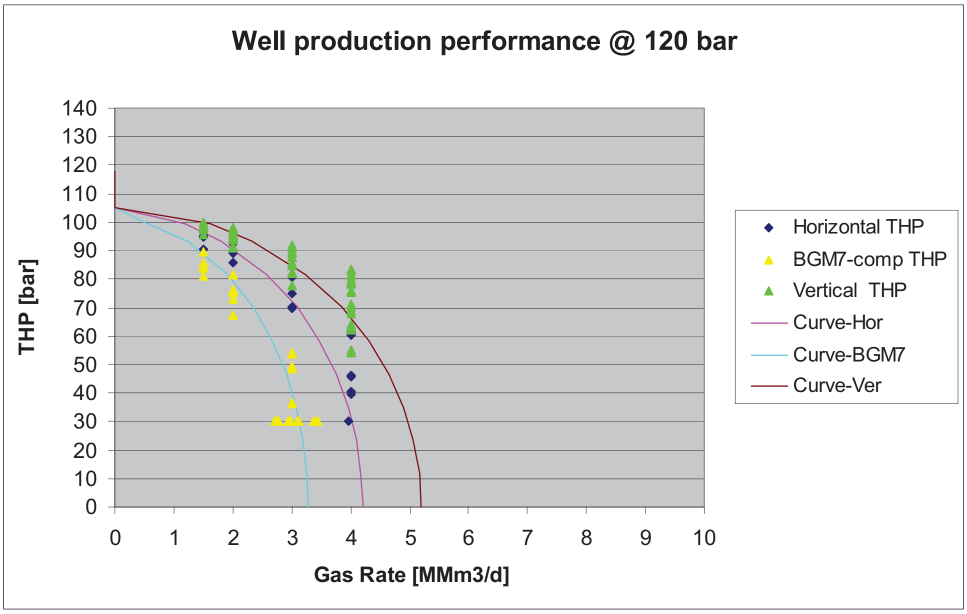


Figure 5-30 **Spread in well-performance in low subsurface realisation (BELL_033_ALT_H06_H11). The plot displays pessimistic performance of wells V_01, H_06 (MAIN) and H11 (BGM-7).**

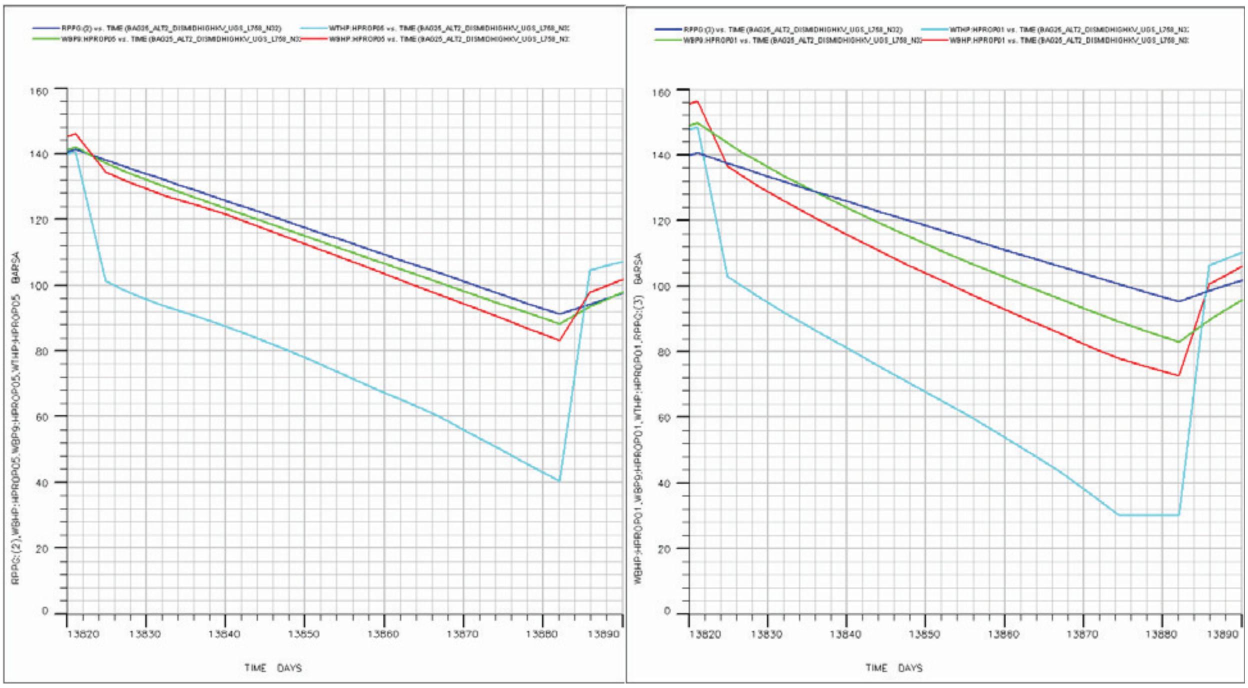


Figure 5-31 Pressure losses in horizontal wells in forecast run DISMDHIGHKV_H05_H01, (20 wells), HOR_05 in Main (left) and HOR_01 in BGM-7 (right). Dark blue is average reservoir pressure of compartment, green is reservoir pressure of well, red is BHP, light blue is THP.

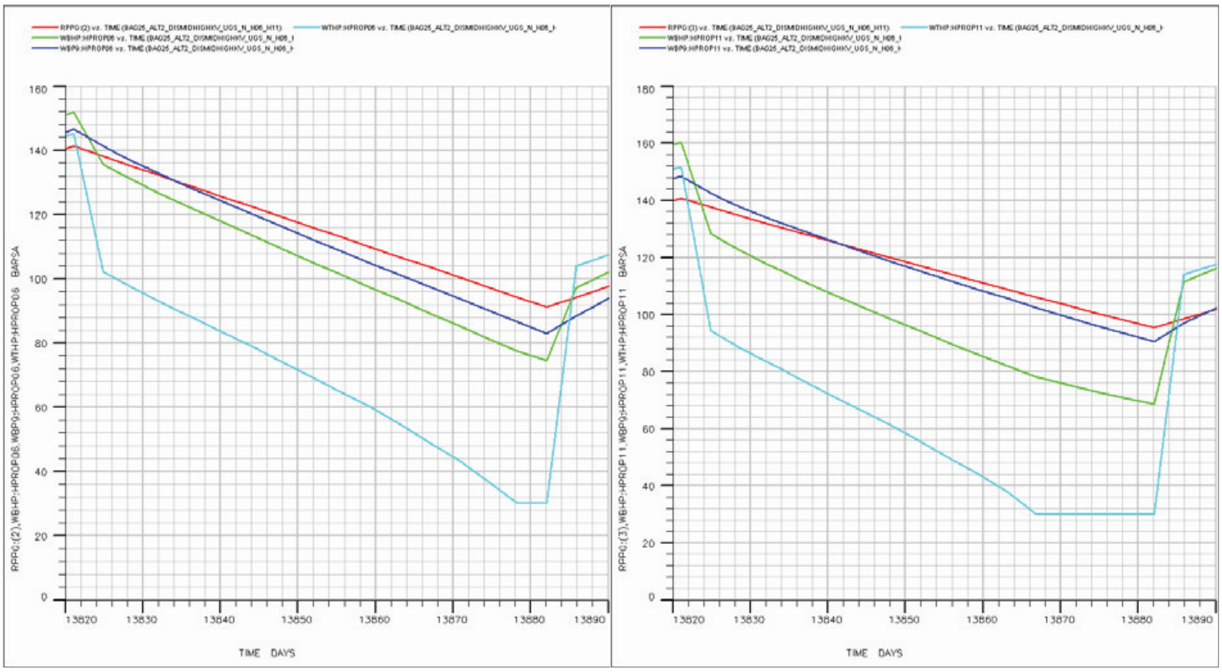


Figure 5-32 Pressure losses in horizontal wells in forecast run (DISMIDHIGHKV_H06_H11), (20 wells), HOR_06 in Main (left) and HOR_11 in BGM-7 (right). Red is average reservoir pressure of compartment, dark blue is reservoir pressure of well, green is BHP, light blue is THP.

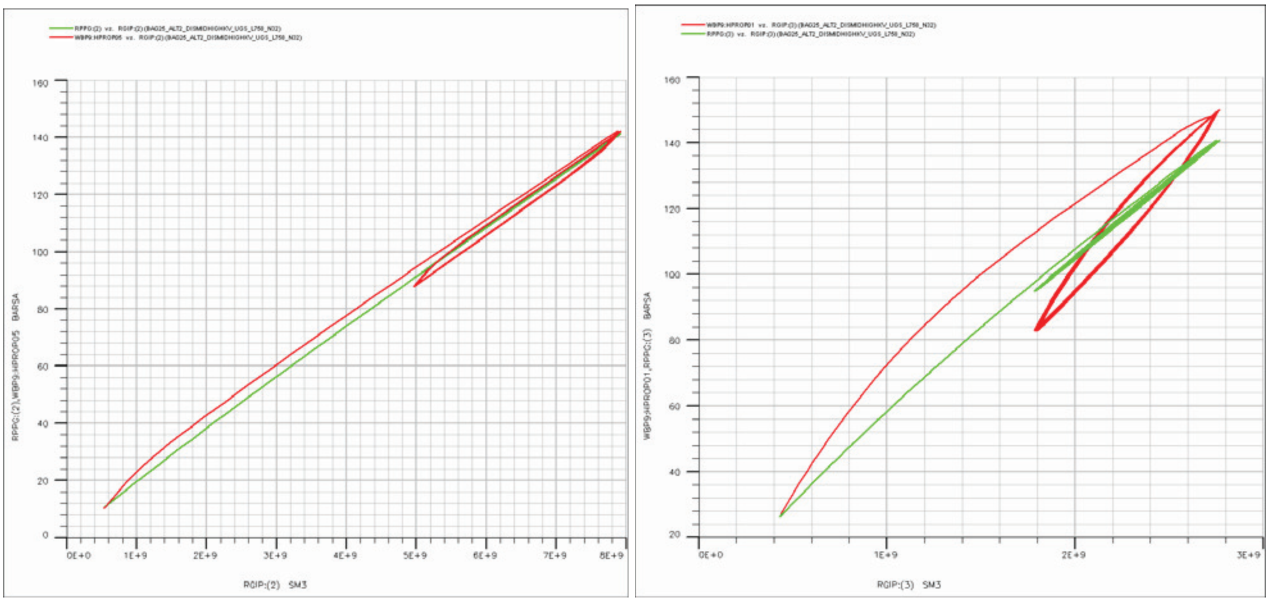


Figure 5-33 Plot of BHP and P_res vs GIP for HOR-5 in Main (left) and HOR-1 in BGM-7 (right). The red curves denote well behaviour (BHP/GIP), the green curves show reservoir-block behaviour (P_reservoir / GIP), model DISMIDHIGHKV_H05_H01.

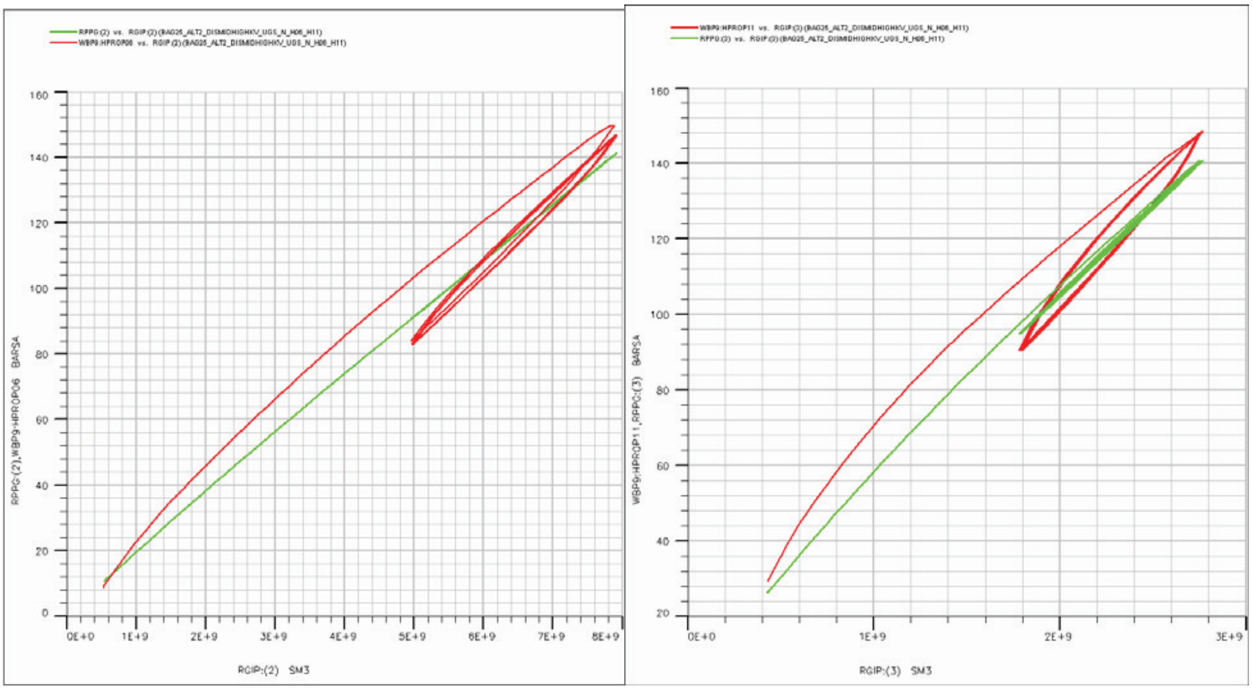


Figure 5-34 Plot of BHP and P_res vs GIP for HOR-6 in Main (left) and HOR-11 in BGM-7 (right). The red curves denote well behaviour (BHP/GIP), the green curves show reservoir-block behaviour (P_reservoir / GIP), model DISMIDHIGHKV_H06_H11.

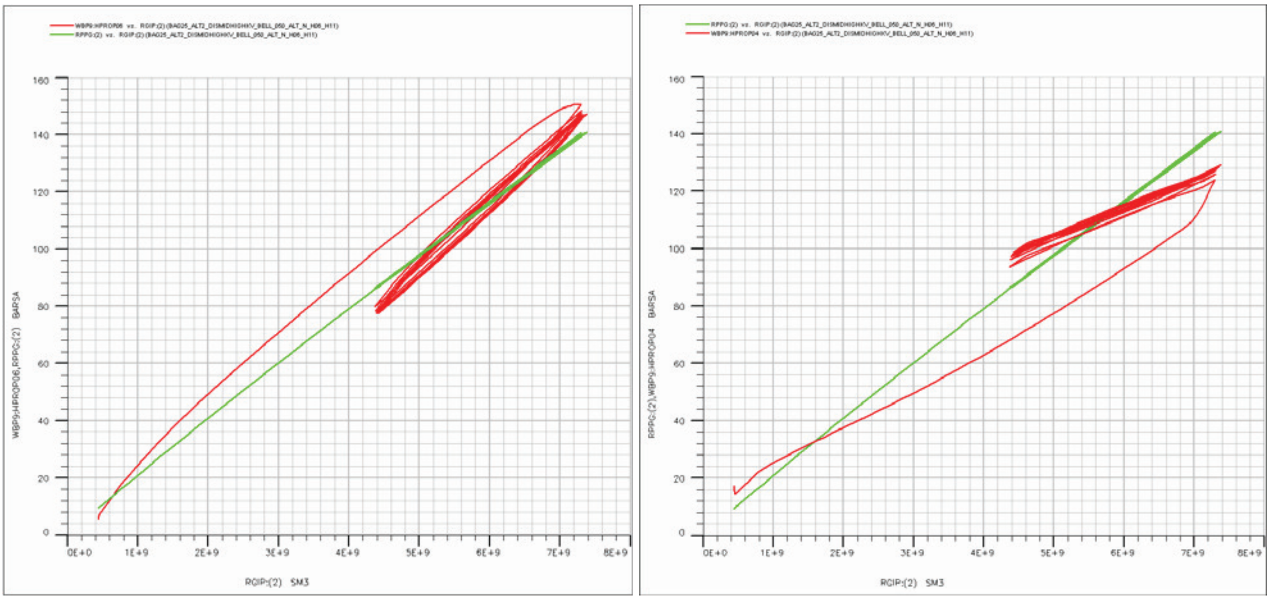


Figure 5-35 BELL_050 model (mid case subusurface), MAIN block, HOR_06 (left) as used for performance parameters and HOR_04 (right), in southern extreme of the block

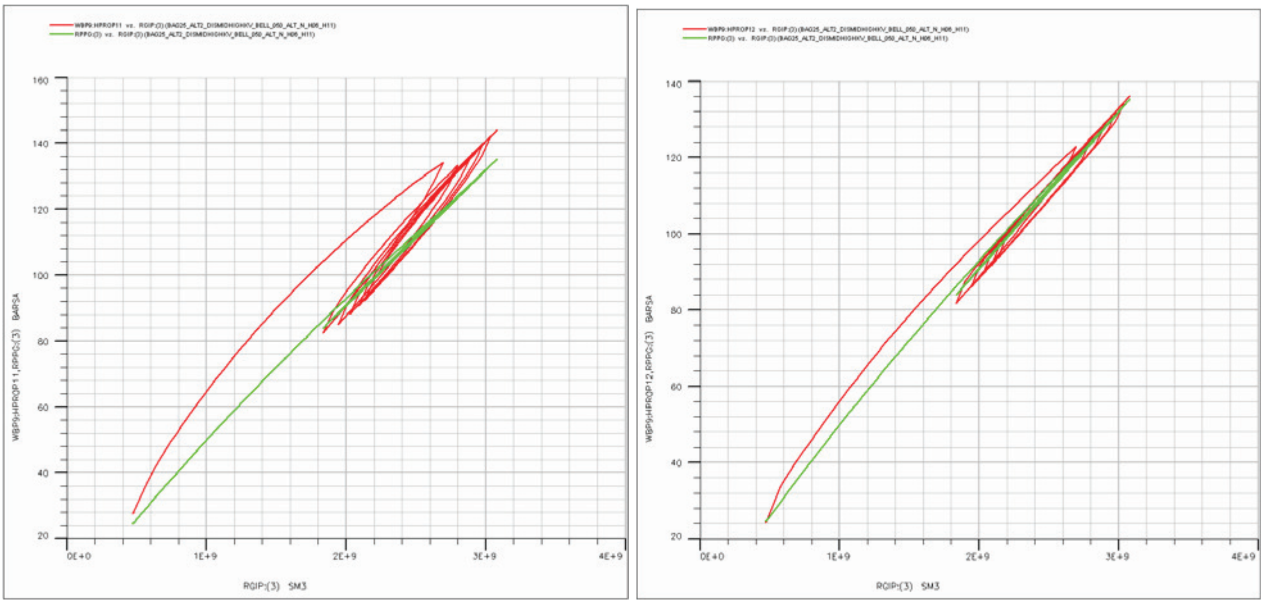


Figure 5-36 BELL_050 model, BLOCK-2, HOR_11 (left) as used for performance parameters and HOR_12 (right) in north of the block were the reservoir pressure represents the average pressure around the well

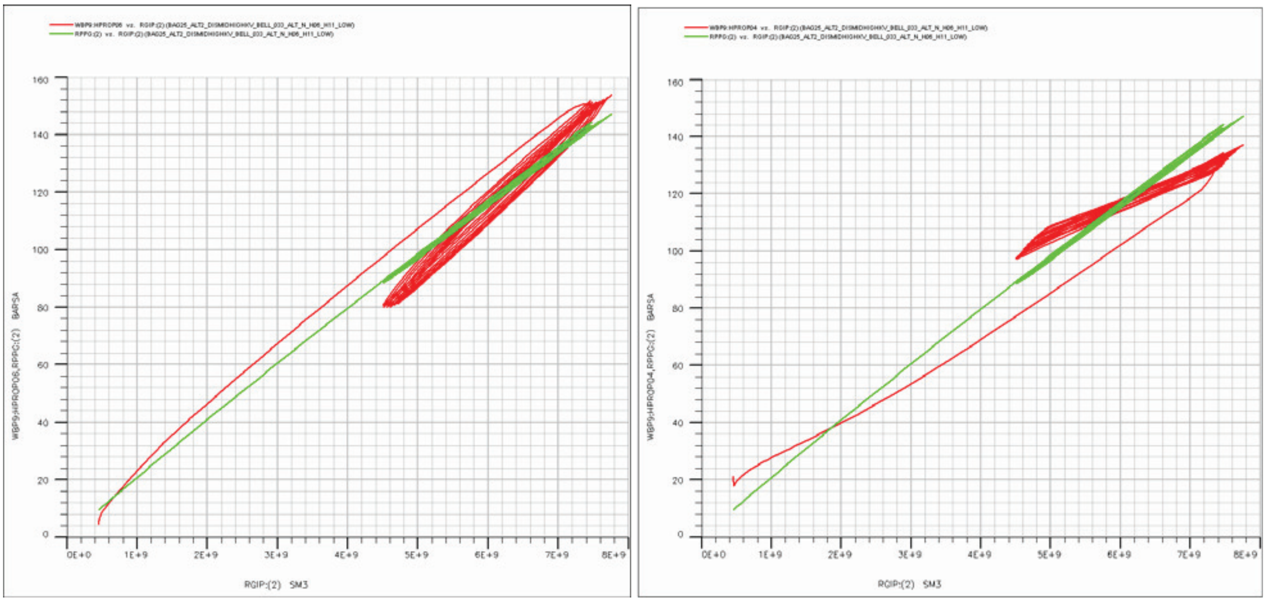


Figure 5-37 BELL_033 model (low case subsurface), MAIN block, HOR_06 (left) as used for performance curves and HOR_04 (right) in the south of the Main block (not used). Swings in HOR_06 ca 20 bar more than the average, while in HOR_04 it is ca 20 bar less, which indicates that capacity in the south is under-utilised and in the north capacity is 'lost'.

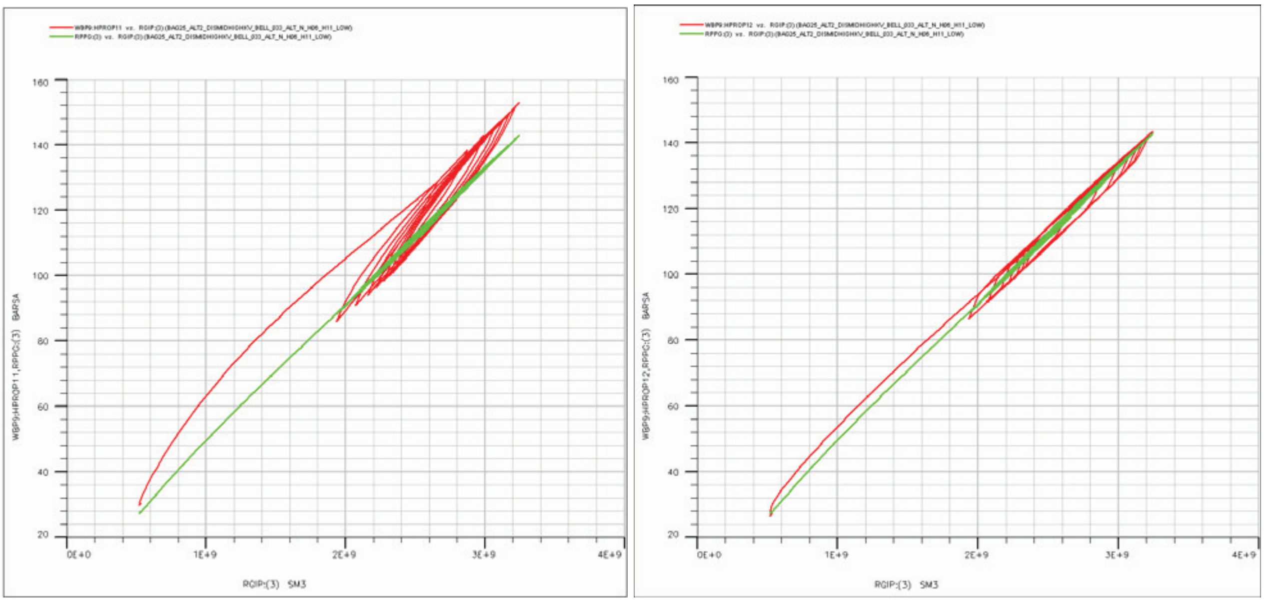


Figure 5-38 BELL_033 model, Block-2, HOR11 in the south (left) and HOR_12 in the north (right). The curves show that average reservoir pressure increases with every new cycle. Due to its very low permeability, the production targets are not met in this low case model, while the injection rate is not changed.

5.7.2 Forecast sensitivities summary

The sensitivities from dynamic modelling were added to the well performance sensitivities in order to get an overall overview of risks for a newly drilled well. The tornado plots were for this reason split up for vertical wells in the MAIN block, horizontal wells in the MAIN block and horizontal wells in Block-2 of BGM-7. The absolute production rates are not given as they can not be compared between Prosper well inflow modelling and dynamic modelling in Eclipse. All rates and rate-differences are however determined at a reservoir pressure of 120 bar and at a flowing THP of 80 bar.

For the vertical well, internal heterogeneity in the Main block is apparently of great importance. The heterogeneity is mainly caused by the difference in local permeability. For horizontal wells, the tubing size, length and roughness is more important than subsurface uncertainty. It should be noted however that in the dynamic sensitivities no horizontal wells were used north of BGM-3A. For a horizontal well in Block-2, the impact of a BELL-shape on permeabilities in the top reservoir section has the greatest impact.

Sensitivity	Well	Base	Low	High	Low	High
Skin	Vert	0	10	0	-4%	0%
	Hor	0	10	0	-22%	0%
CGR [m3/m3]	Vert	3 (0.5)	56 (10)	0	-3%	0%
(stb/MMscf)	Hor	3 (0.5)	56 (10)	0	-3%	0%
WGR [m3/m3]	Vert	0	56 (10)	0	-13%	0%
(stb/MMscf)	Hor	0	56 (10)	0	-26%	0%
Roughness [inch]	Vert	0.00015	0.005	0.00005	-11%	3%
	Hor	0.00015	0.005	0.00005	-23%	4%
Tubing-size OD [inch]	Vert	7 5/8"	5.5"	9 5/8"	-30%	13%
	Hor	7 5/8"	5.5"	9 5/8"	-46%	52%
dSdQ_DISMIDHIGHKV	Vert	1979_test	* 2	/ 4	-17%	7%
$[MMsm3/d]^{-1}$	Hor_Main	1979_test	* 2	/ 4	-17%	2%
	Hor_Block2	1979_test	* 2	/ 4	-18%	9%
Subsurface model	Vert	BELL_050	BELL_033	DISMIDHIGHKV	-6%	3%
	Hor_Main	BELL_050	BELL_033	DISMIDHIGHKV	-6%	6%
	Hor_Block2	BELL_050	BELL_033	DISMIDHIGHKV	-4%	54%
Internal heterogeneity	Vert	V01	V08	V07	-9%	21%
DISMIDHIGHKV	Hor_Main	H06	H04	H05	-13%	3%
	Hor_Block2	H11	H11	H12	0%	12%
Internal heterogeneity	Vert	V01	V08	V07	-5%	23%
BELL_050	Hor_Main	H06	H04	H05	-11%	7%
	Hor_Block2	H11	H13	H01	-5%	16%
Internal heterogeneity	Vert	V01	V08	V07	-6%	32%
BELL_033	Hor_Main	H06	H04	H05	-1%	0%
	Hor_Block2	H11	H13	H01	-5%	0%
dSdQ_BELL_050	Vert	49	99	12	-11%	15%
$[MMsm3/d]^{-1}$	Hor_Main	49	99	12	-10%	14%
	Hor_Block2	49	99	12	-4%	11%

Table 5-10 Forecast sensitivities summary table.

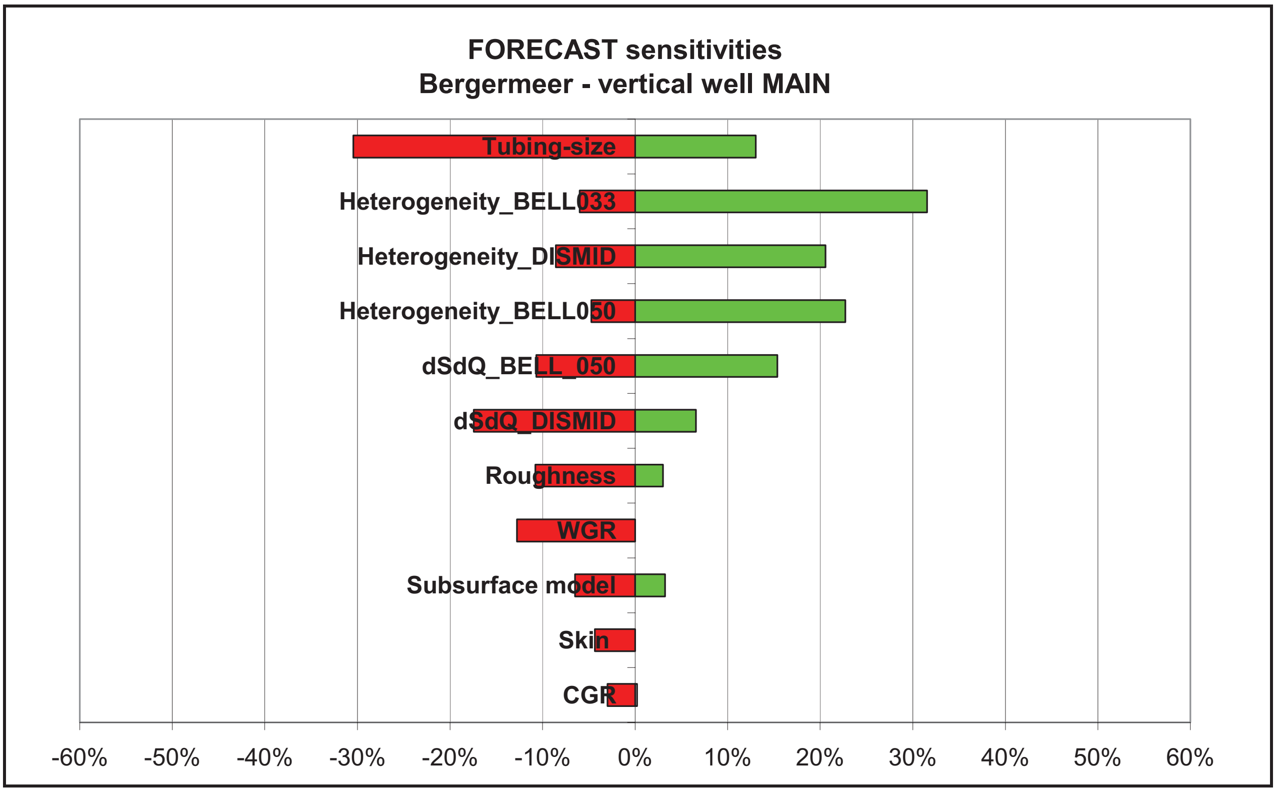


Figure 5-39 Tornado plot forecast sensitivities vertical well in Main block

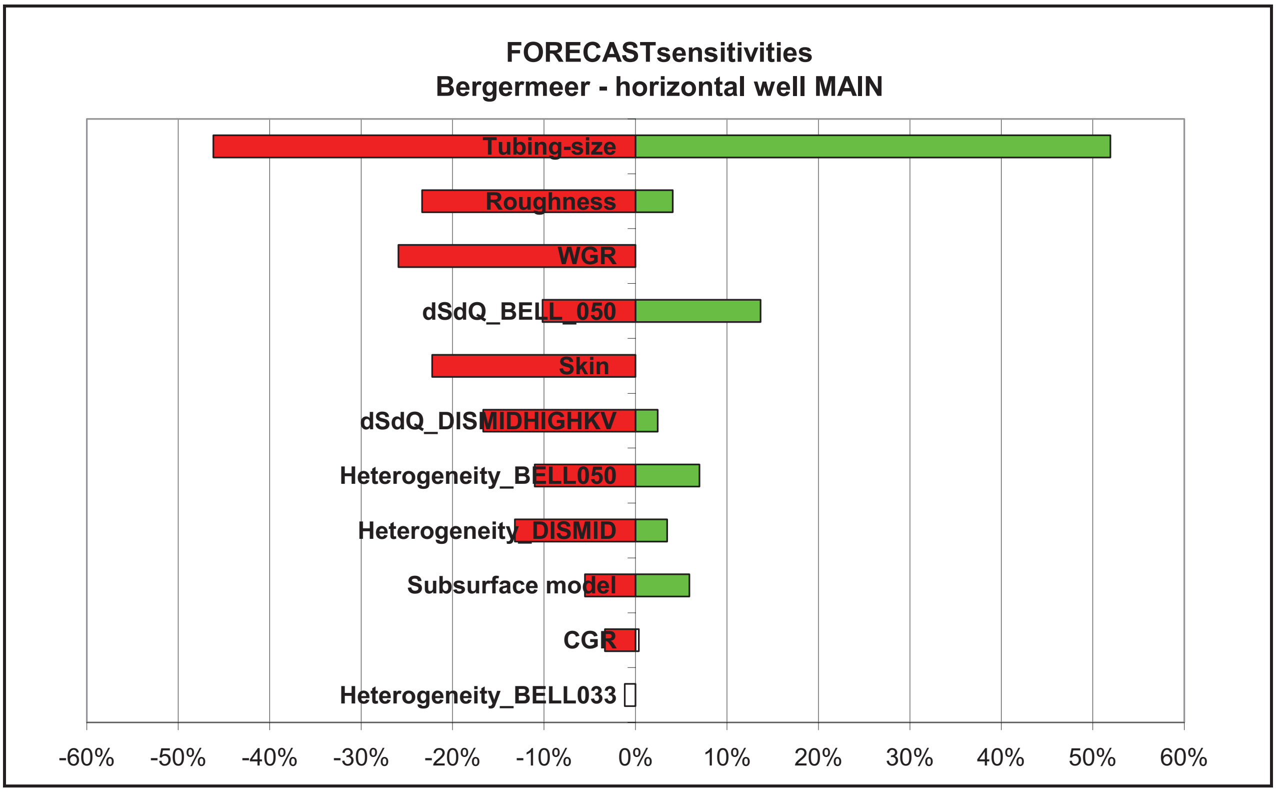


Figure 5-40 Tornado plot forecast sensitivities horizontal well in Main block

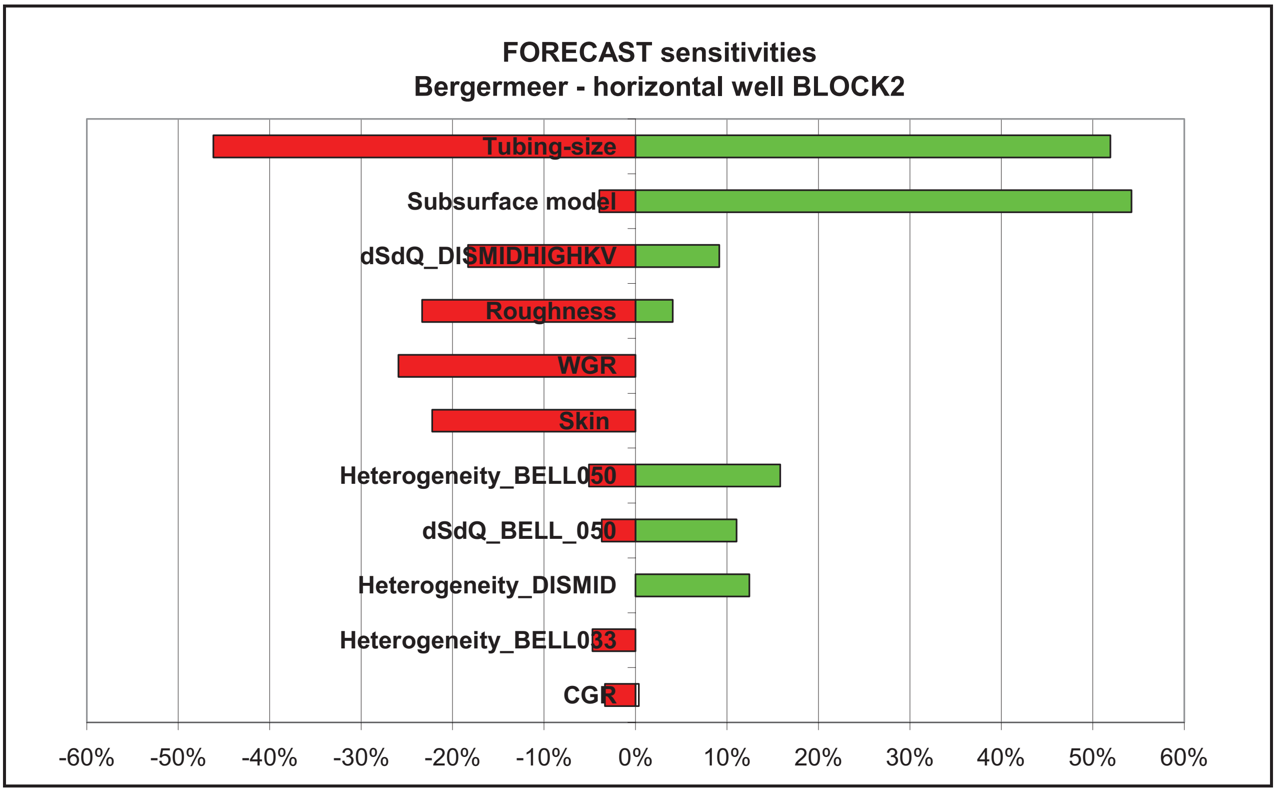


Figure 5-41 Tornado plot forecast sensitivities horizontal well in Block-2.

5.7.3 Groet

Historically, the Groet and Bergermeer fields were produced simultaneously. The reservoir pressure of Groet has been on either side of Bergermeer, see Figure 2-2, with a maximum pressure difference of ca 35 bar. Analysis of the production and pressure data concluded that the fields show no or very little communication, see section 2.1. The fault between the two fields (fault_at_spill) was put in as virtually sealing in our model. It is not known what the sealing capacities of the fault are at larger than historical pressure differentials. A sensitivity was therefore run on the sealing capacity of the dividing fault in the UGS phase. The transmissibility was multiplied by a factor 100, still giving a history match of the production phase, but showing an increase of reservoir pressure in Groet during the Bergermeer UGS phase, see Figure 5-42.

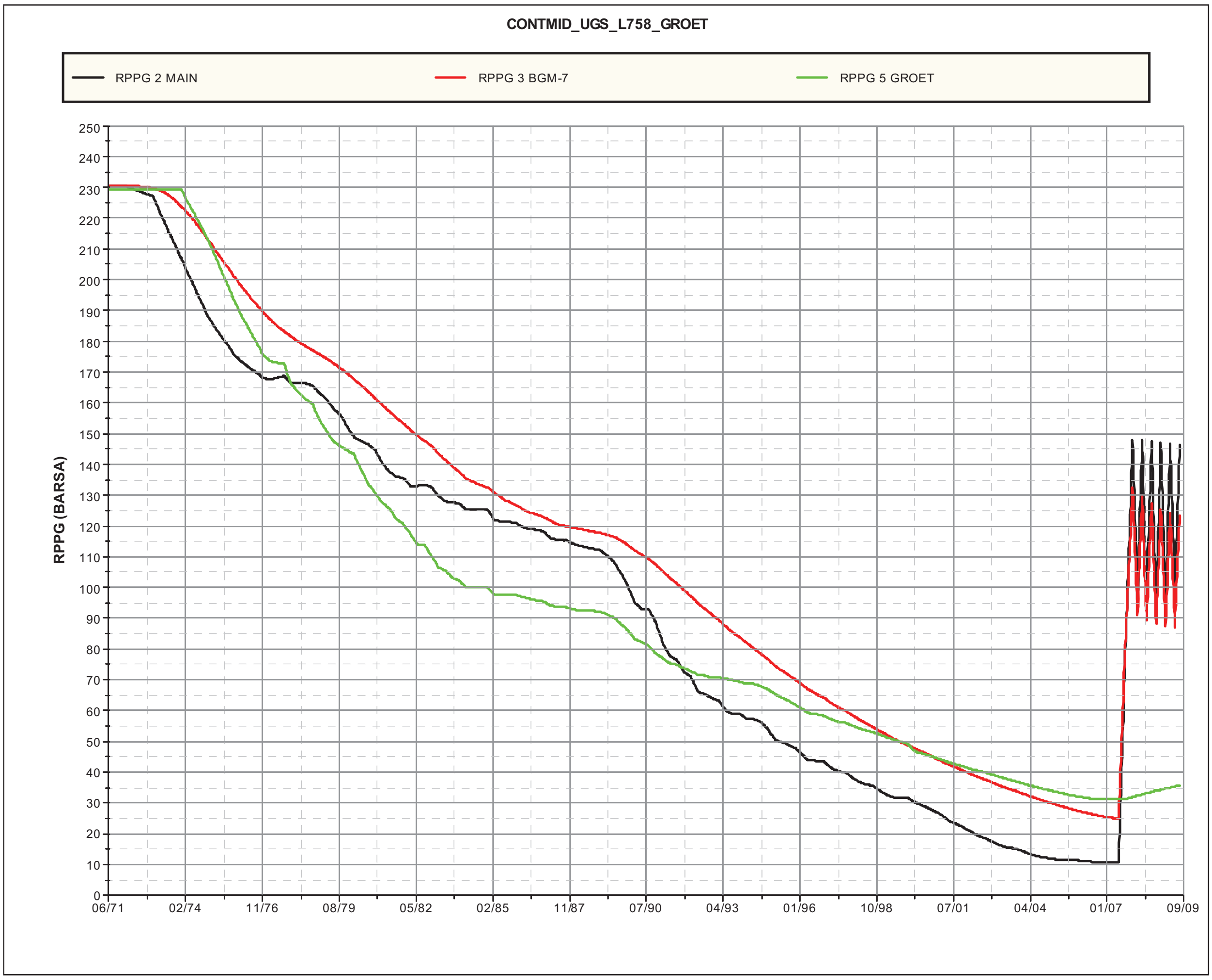


Figure 5-42 Reservoir pressures, Main, BGM-7 and Groet, leaking fault model, transmissibility multiplied by 100 (0.0002→ 0.02), HM and UGS phase

The sensitivity run shows that during the UGS phase the BGM-7 block decreases ca 10 bar in 5 cycles due to leakage to Groet, see Figure 5-43. The reservoir pressure in Groet increases with ca 4 bar. The reservoir pressure in the Main block is initially not affected in the base case model, with the eastwards extension of the dividing fault (2B_alt2). As the exact location of the fault can not be seen on seismic, a possible direct spill to the Main block can not be excluded. It is therefore highly recommended to monitor the pressure in Groet closely during the UGS phase.

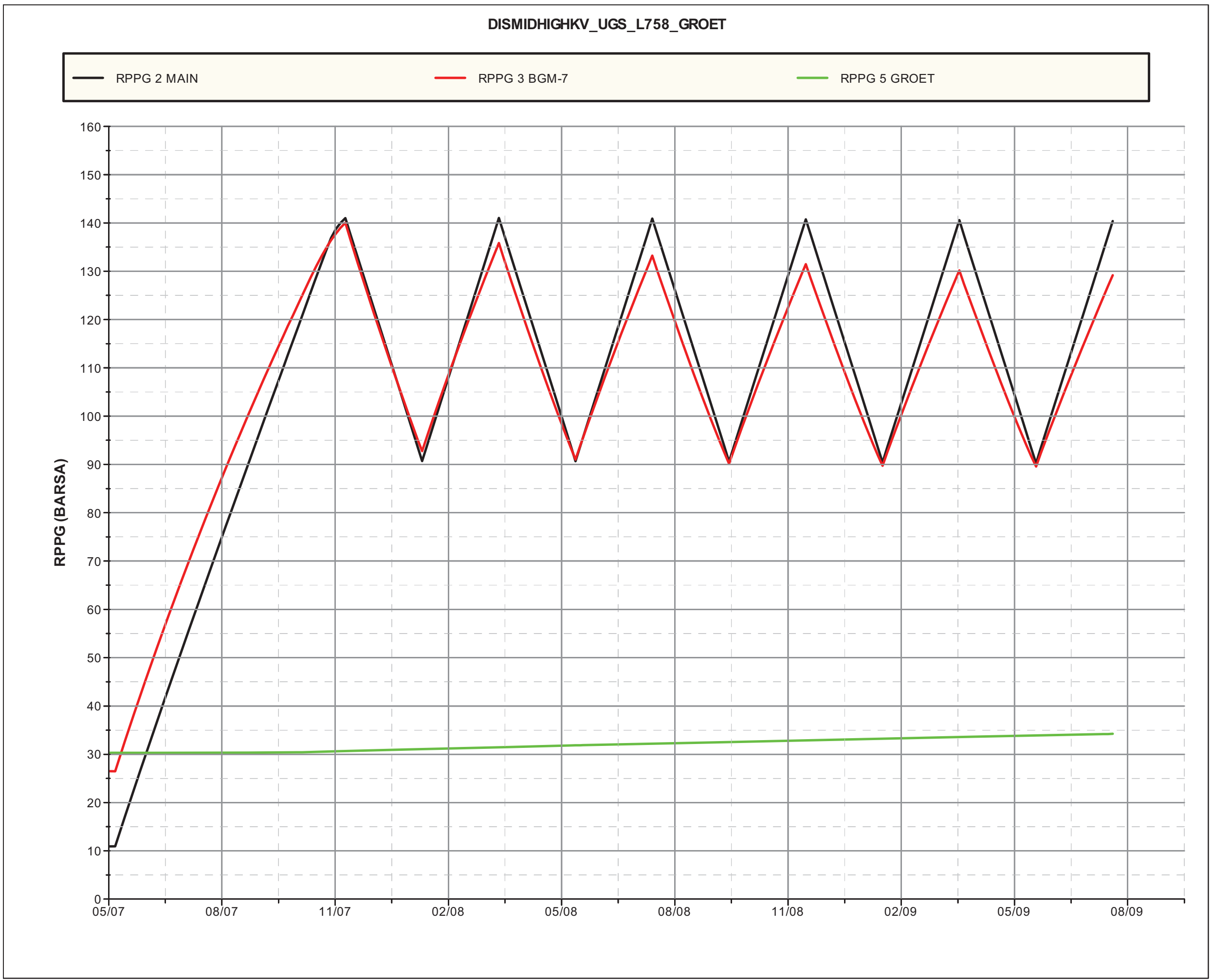


Figure 5-43 **Reservoir pressures, Main, BGM-7 and Groet, leaking fault model, transmissibility multiplied by 100 (0.0002→ 0.02), zoom in on UGS phase**

5.7.4 Local Grid Refinement

As sensitivity, the grid was refined from 100x100x10 to 33x33x5 m blocks in the 'sweet spot', to see if water coning and well interference would be modelled better in a finer grid. The 'sweet spot' in the south includes all 11 vertical UGS wells. The run was done without any horizontals in the Main block. The changes in the height of the water cones around the wells are in the order of 1 to 2 meters, see

Figure 5-44 Water contact changes due to grid refinement. In BGM-7 the contact rises, while in BGM-1 (Main) the contact falls with 1-2 m.. The Main block shows slightly smaller coning behaviour, the BGM-7 block slightly larger.

Figure 5-45 shows that the pressure gradients within the LGR during the production phase are very small and are already sufficiently captured by the original grid size of 100x100x10 meters.

Figure 5-46 and Figure 5-47 show the pressure gradients during the UGS injection phase in the Main and BGM-7 blocks. The Main block includes the LGR, although the pressure varies only 2 bar in the area. In

BGM-7, the original gridblock-size captures the existing pressure variations of ca 8 bar well enough.

A comparison of the capacity parameters showed that with LGR, the model is slightly more optimistic than without the LGR. The difference is small, however, again confirming the conclusion that the base grid size seems sufficient.

	Group1		Group2		Group 3		Group1		Group2		Group 3	
	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pr	Qlim/THPl	THPlim/Pr	Qlim/THPlim	THPlim/Pres	Qlim/THPlim	THPlim/Pr	Qlim/THPl	THPlim/Pr
Prod 95	0.000	0.00	0.045	0.87	0.052	0.87	0.000	0.00	0.050	0.87	0.056	0.87
Inj 95	0.000	0.00	0.042	0.85	0.050	0.88	0.000	0.00	0.048	0.87	0.055	0.88
Prod 120	0.000	0.00	0.046	0.87	0.053	0.87	0.000	0.00	0.052	0.87	0.058	0.87
Inj 120	0.000	0.00	0.044	0.87	0.051	0.88	0.000	0.00	0.047	0.86	0.056	0.88
Prod 145	0.000	0.00	0.045	0.87	0.053	0.87	0.000	0.00	0.050	0.86	0.057	0.87
Inj 145	0.000	0.00	0.042	0.86	0.050	0.87	0.000	0.00	0.048	0.87	0.055	0.88

Table 5-11 Comparison of 'DISMID_HIGHKV' UGS run with (left) and without (right) local grid refinement.

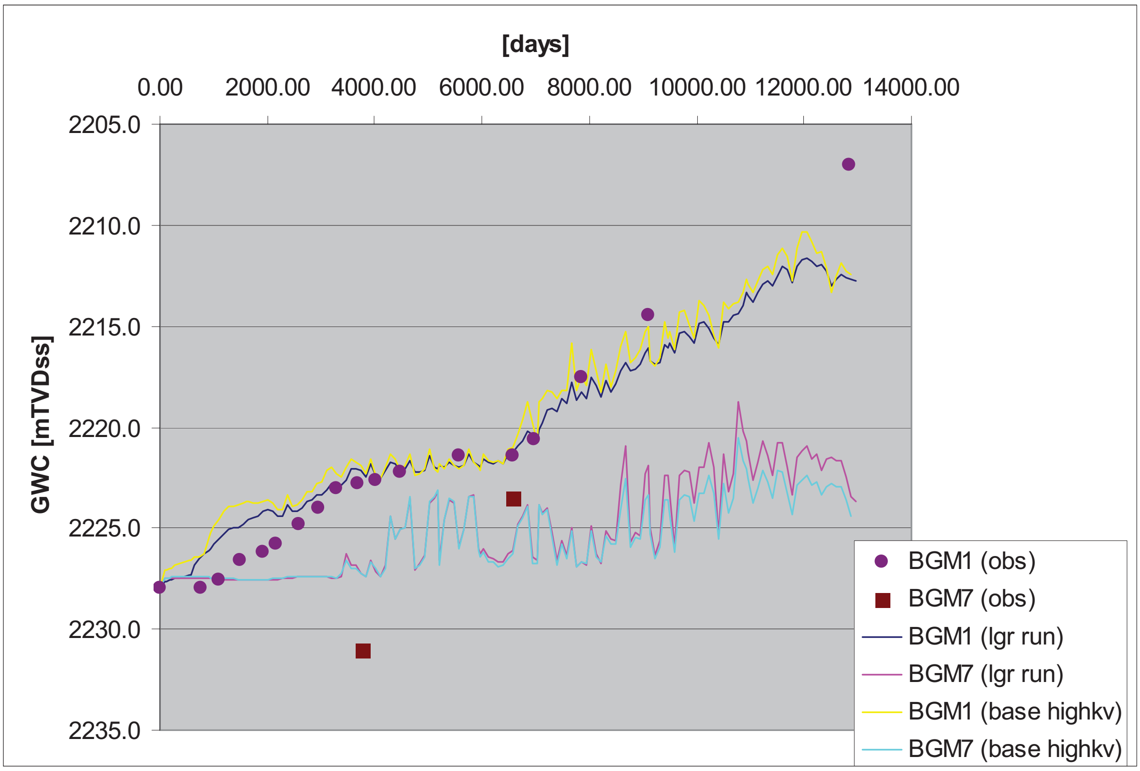


Figure 5-44 Water contact changes due to grid refinement. In BGM-7 the contact rises, while in BGM-1 (Main) the contact falls with 1-2 m.

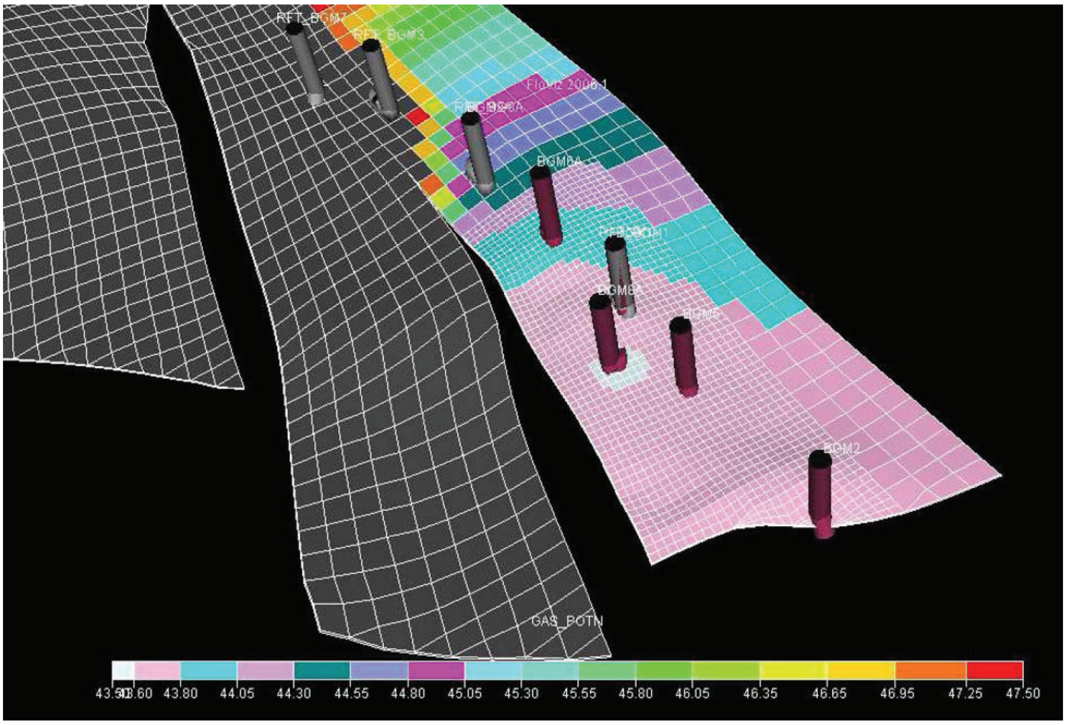


Figure 5-45 Plot of pressure (GAS_POTN) gradients at the end of HM (plot is @ 1-May-1996); the shape of the contours shows that in the LGR grid, the pressure gradient-size is ample @ 0.2 bar

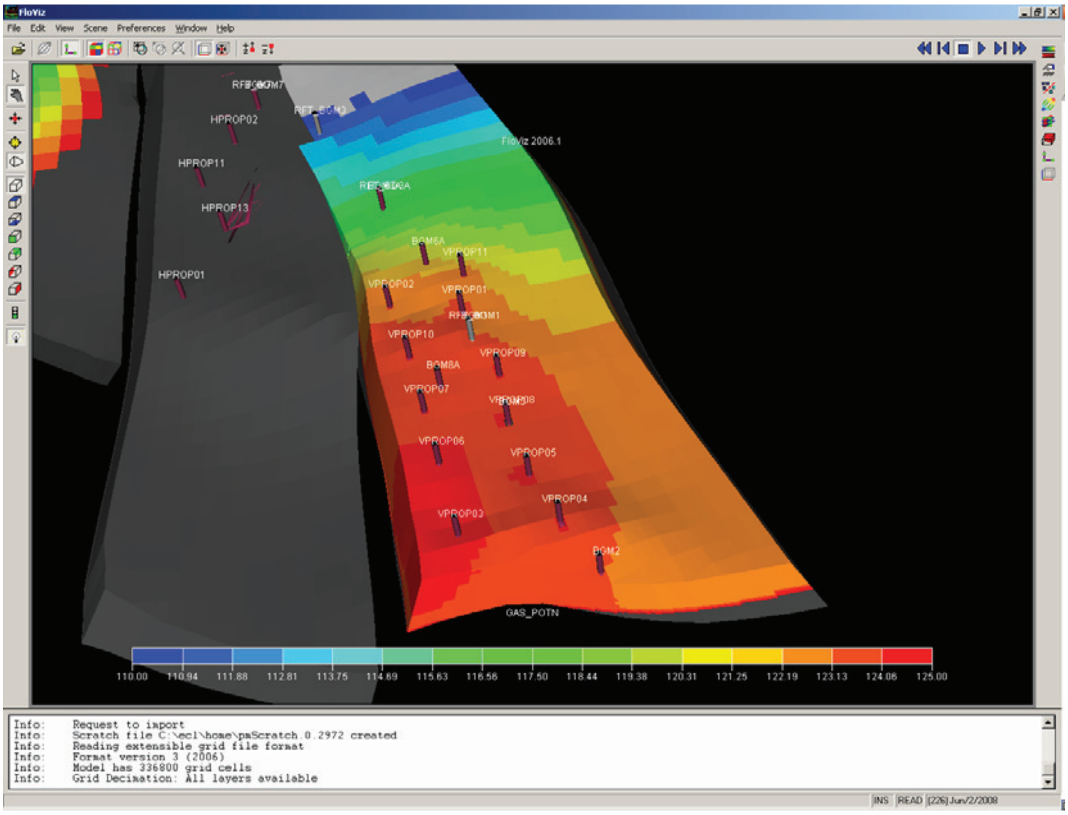


Figure 5-46 Plot of pressure gradients during the UGS injection phase, the Main block includes a LGR for the 'sweet spot' with the vertical wells. The gradient size in the LGR is ca 2 bar.

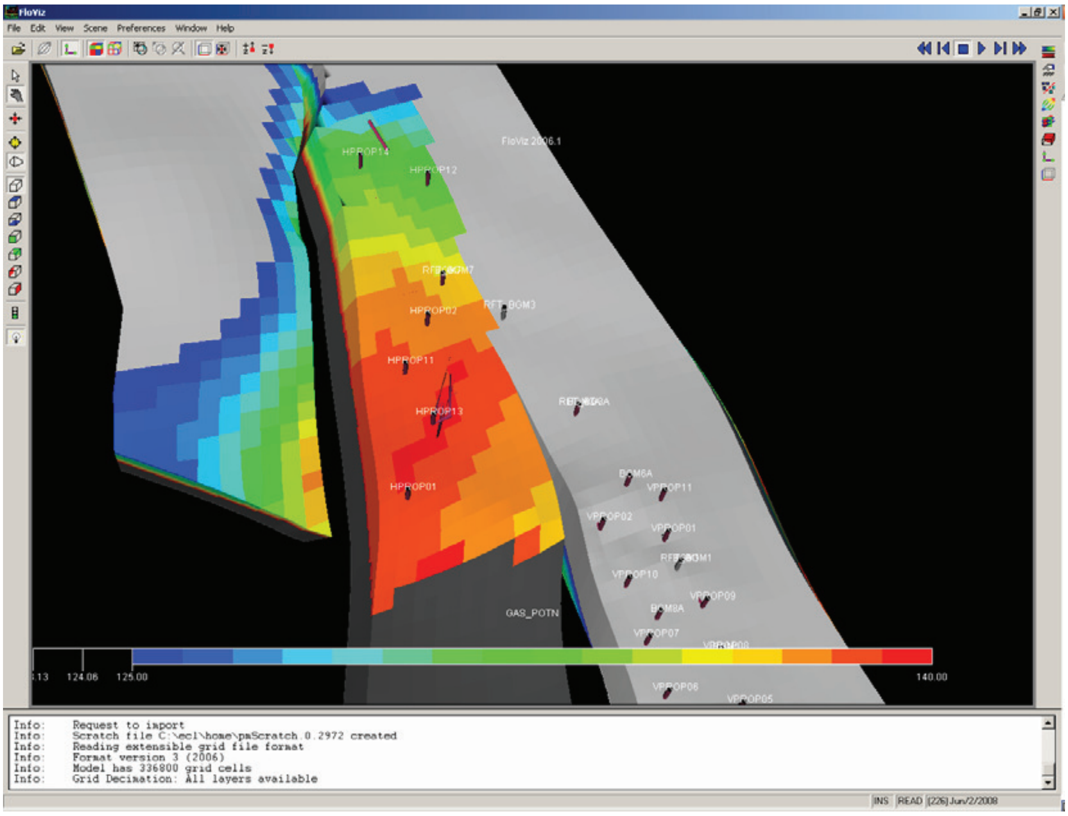


Figure 5-47 **Plot of pressure gradients during the UGS injection phase, the BGM-7 block does not have LGR. The gradient size of ca 8 bar in BGM-7 is well captured by the original gridblock-size.**

5.8 Drilling and filling up sequence

Filling up of the reservoir was checked with the dynamic model in order to control pressures and find the best drilling sequence. The assumption was to be able to drill for 9 months only because of environmental regulations. During the other 3 months, the new wells were to be used for filling up the reservoir. The base case model with 7 5/8" Tbg and 20 wells was used. The maximum FTHP per year was given by TAQA. It was found that in the first year 4 wells needed to refill the reservoir pressure from 9 to ca 35 bar. The drilling sequence is summarised as follows:

- Year1: FTHP 60 bar 4 vert. MAIN 1 hor. BGM-7
- Year2: FTHP 60 bar 3 vert. MAIN 2 hor. BGM-7
- Year3: FTHP100bar 4 vert. MAIN 1 hor. BGM-7
- Year4: FTHP 150bar 4 vert. MAIN 1 hor. BGM-7

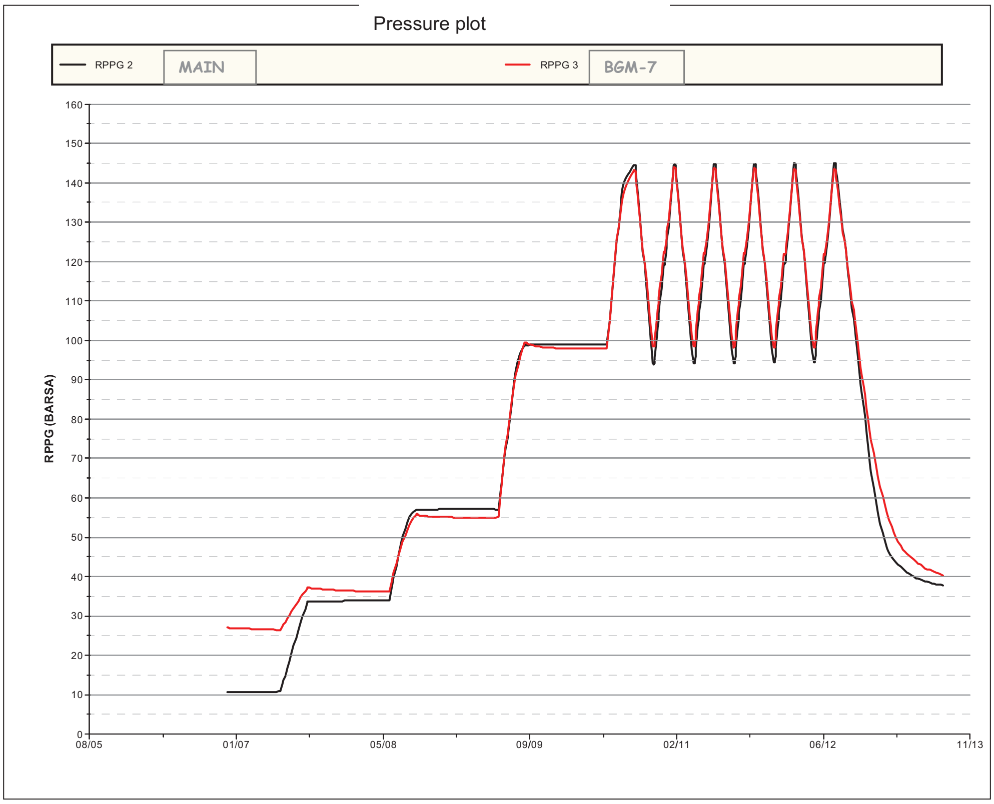


Figure 5-48 Reservoir pressures of optimal drilling sequence, 5 cycles and end-of-fieldlife modelled in Eclipse.

The total injected gas-volumes for each cycle are given in Table 5-12. For a discussion of the FGIIP and internal division of volumes between the Main and BGM-7 blocks, see section 2.3.

	PRES [BAR]		V_GAS [BSM3]			V_INJ [BSM3]		
YEAR			**MAIN**	**CMP-7**	**TOTAL**	**MAIN**	**CMP-7**	**TOTAL**
0	10	26	0.55	0.45	1.00	0	0	0
1	34	36	1.75	0.60	2.35	1.20	0.15	1.35
2	57	55	3.05	0.95	4.00	1.30	0.35	3.00
3	99	98	5.45	1.85	7.30	2.40	0.90	6.30
4	145	143	8.15	2.85	11.0	2.70	1.00	10.0

Table 5-12 Bergermeer UGS filling up pressures and volumes.

5.9 End-of-field-life

The end-of-field-life was modelled with:

- field deliverability constraint 50 MM m3/d

- FTHP minimal 30 bar
- duration 1 year

The field deliverability constraint was translated to a well constraint of 2.5 MM sm3/d for each of the 20 wells. Most wells produce at plateau for 3-4 month, after which they switch to FTHP constraint of 30 bars, at a reservoir pressure of ca 75 bar. The verticals die out because of lift-constraints after a total 6 – 9 months, while the horizontal wells keep producing for a total of 7 – 13 months. The final reservoir pressure attained with the constraints mentioned above is ca 40 bar, see Figure 5-48. The field gas production rate is plotted in Figure 5-49.

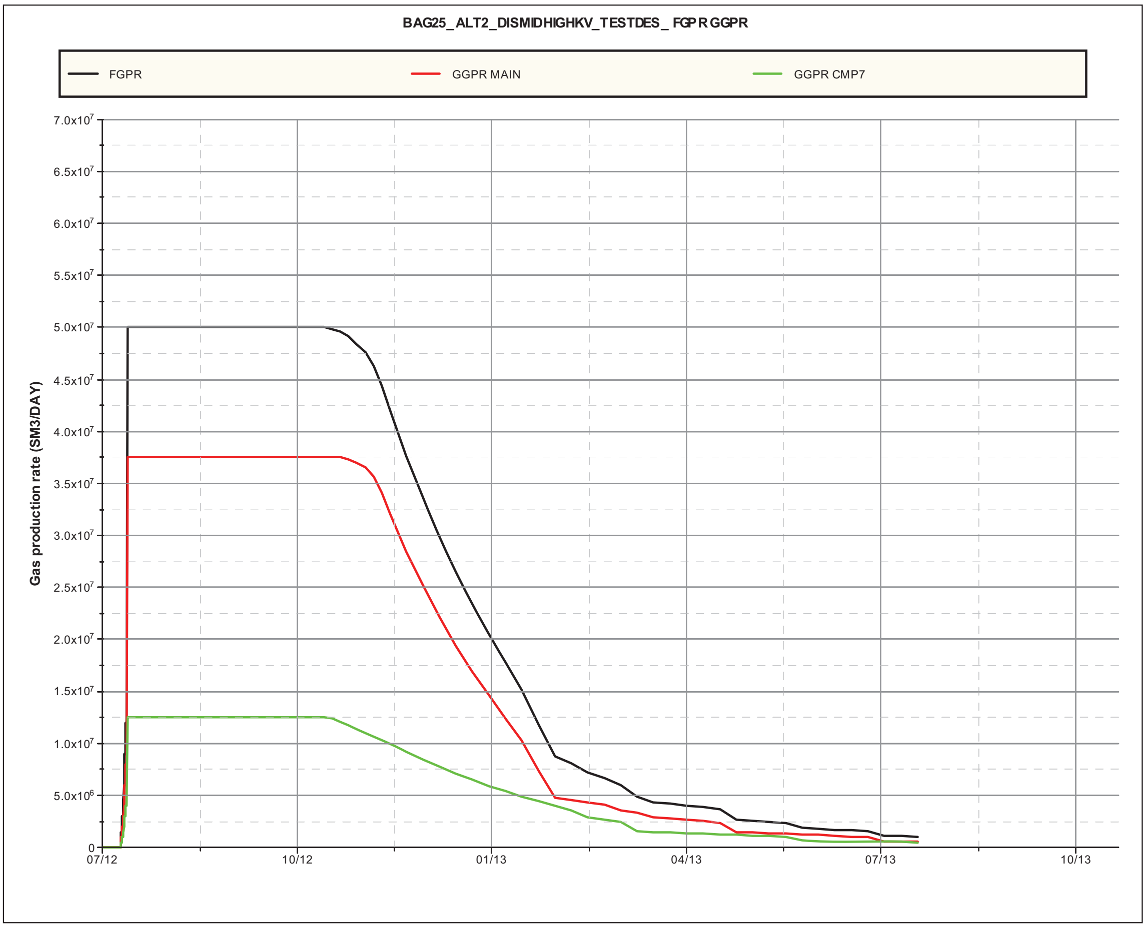


Figure 5-49 **End-of-fieldlife model (Eclipse), gas-rates per compartment for base case forecast (20 wells, 7 5/8" tbg)**

6 Summary and recommendations

The Bergermeer field was history matched and the UGS phase dynamically modelled. Results from an extensive injection test during the summer of 2007 were incorporated in the dynamic model. Well performance modelling has finally provided the definition the main parameters for pressure losses in the tubing. The main conclusions are:

- High permeable reservoir which is suitable for gas storage
- Not supported by an aquifer
- No or very little water production is expected
- Tilting of GWC explained by presence of best reservoir (‘sweet spot’) in south with most producers / injectors
- The GWC-rise will be reversed by gas injection
- Water breakthrough risk is greatest in the northern area of the field
- The field has two main compartments divided by partially sealing fault
- The Main block is further compartmentalised by at least two smaller subseismic, non-sealing faults
- Horizontal wells are needed in block-II (BGM-7) and in the deeper regions of block I (Main)

  [deleted text because of confidentiality]
- The pressure losses in the tubing are much greater than the pressure loss near the wellbore at the designed production and injection rates of the UGS
- Pressure losses in the tubing can be greatly reduced by lowering the tubing-roughness
- The sealing potential of the northern boundary fault to Groet is not known at larger pressure differences than 35 bar

The key uncertainties for the subsurface are (with potential mitigating measures as recommendation):

- Relative volumes Main / BGM-7 (position of dividing fault).
  - Continued pressure monitoring in BGM (on either side of the BGM7/Main fault) during repressurization.
- Top Rotliegend in the BGM-7 block is uncertain.
  - Well in the south of block-2 / new 3D
- Reservoir quality and top Rotliegend in the north of the field, due to lack of well control.
  - Well northeast of BGM-3A / new 3D
- Sealing potential of the fault between Bergermeer / Groet at higher differential pressures.
  - Continuous monitoring of pressures in GRT1
- Possible discrepancy between well test and history match permeabilities.
  - Simulation of the well tests done in Eclipse (i.s.o. a PTA package like Kappa) to accurately assess the effect of heterogeneities
  - Running of PLT’s during future tests to better define contributing reservoir section height, which is essential to calculate K from K*H

- Non-Darcy skin values (D) are based on welltests from current Bergermeer completions
    - Assess impact of openhole gravelpack / slotted liner on non-Darcy D-value versus perforated casing/liner

The key uncertainties for well planning with recommended potential mitigating measures are:

- Steel quality of tubing
    - Investigate UGS standard
- Mechanical well-skin due to drilling and completion in low pressured reservoirs
    - Investigate analogues / gravelpack specialist
- Amount of re-vapourised water / condensate during production cycle
- Quality of the injection gas

References

[1] Bergermeer UGS Subsurface Modelling, Horizon Energy Partners, 2007

[2] Fundamentals of reservoir engineering, L.P.Dake, Elsevier, Amsterdam, 1978

[3] Fundamentals of gas reservoir engineering” by J. Hagoort, Elsevier, Amsterdam

[4] TAQA, email 12-7-2007.

7 Appendix I

7.1 Injection Test Details

Table 7-1 Overview of injection rates during Bergermeer injection test 2007

INJECTION TEST 2007		AVERAGE INJ RATE			AVERAGE INJ RATE			
DATE	TIME	BGM-1	BGM-2	BGM-6	BGM-1	BGM-2	BGM-6	TOTAAL
	hrs	m3/hr	m3/hr	m3/hr	M m3/d	M m3/d	M m3/d	M m3/d
7/24/2007 6:00	6.0	20205	0	0	485	0	0	485
7/24/2007 12:00	43.0	11443	0	0	275	0	0	275
7/26/2007 7:00	119.0	17832	0	0	428	0	0	428
7/31/2007 6:00	15.0	21580	0	0	518	0	0	518
7/31/2007 21:00	9.0	20212	0	0	485	0	0	485
8/1/2007 6:00	31.5	24444	0	17408	587	0	418	1004
8/2/2007 13:30	40.7	0	0	0	0	0	0	0
8/4/2007 6:10	48.0	25039	0	18391	601	0	441	1042
8/6/2007 6:10	47.8	27472	17118	21467	659	411	515	1585
8/8/2007 6:00	24.0	26991	16829	20366	648	404	489	1540
8/9/2007 6:00	24.2	30564	18565	23139	734	446	555	1734
8/10/2007 6:10	24.0	32084	19313	24150	770	464	580	1813
8/11/2007 6:10	101.3	33119	19757	24510	795	474	588	1857
8/15/2007 11:30	103.2	36630	21028	27172	879	505	652	2036
8/19/2007 18:40	144.8	35859	20557	26507	861	493	636	1990
8/25/2007 19:30	2.5	0	0	0	0	0	0	0
8/25/2007 22:00	32.0	35691	18631	26493	857	447	636	1940
8/27/2007 6:00	12.5	40479	20486	0	971	492	0	1463
8/27/2007 18:30	11.5	27333	13292	20463	656	319	491	1466
8/28/2007 6:00	32.0	35551	17562	27435	853	421	658	1933
8/29/2007 14:00	65.0	35048	17843	26891	841	428	645	1915
9/1/2007 7:00	10.0	39033	20895	30000	937	501	720	2158
9/1/2007 17:00	2.0	0	0	0	0	0	0	0
9/1/2007 19:00	40.0	38759	19535	30241	930	469	726	2125
9/3/2007 11:00	3.5	0	0	0	0	0	0	0
9/3/2007 14:30	39.5	38205	19516	29756	917	468	714	2099
9/5/2007 6:00	24.0	0	0	0	0	0	0	0
9/6/2007 6:00	104.0	38478	19495	29923	923	468	718	2110
9/10/2007 14:00	496.0	38101	17800	31912	914	427	766	2107
10/1/2007 6:00	0.0	0	0	0	0	0	0	0

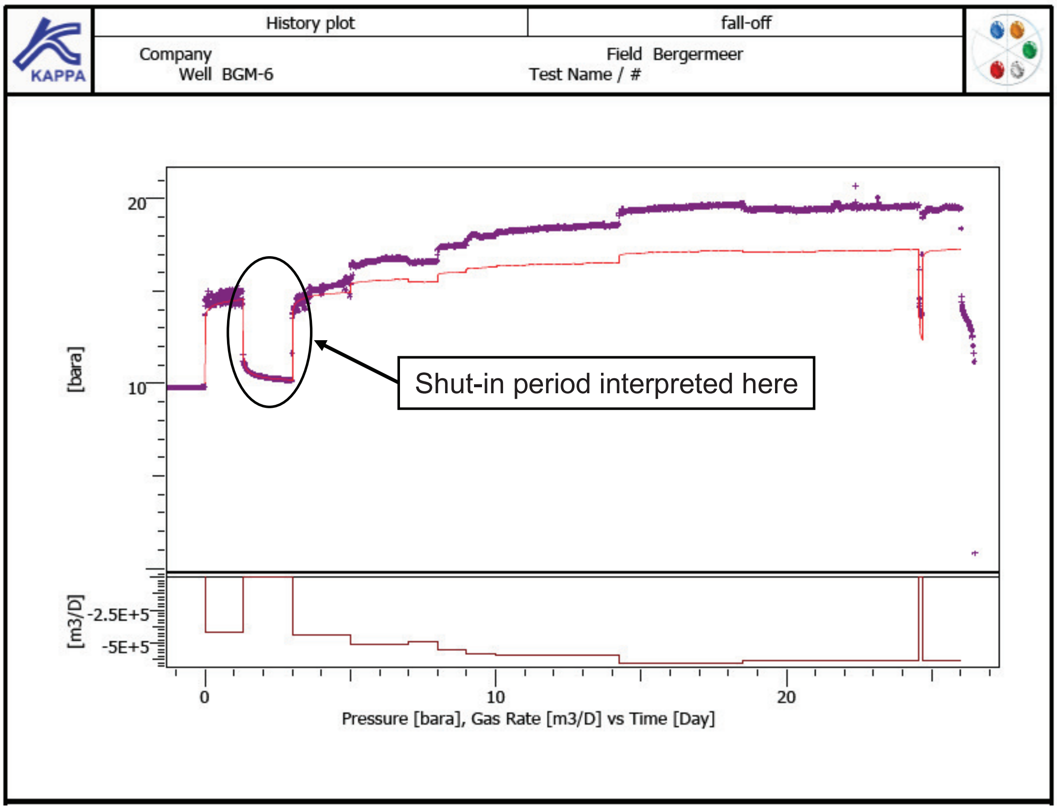


Figure 7-1 BGM-6 plot of interpreted fall-off period

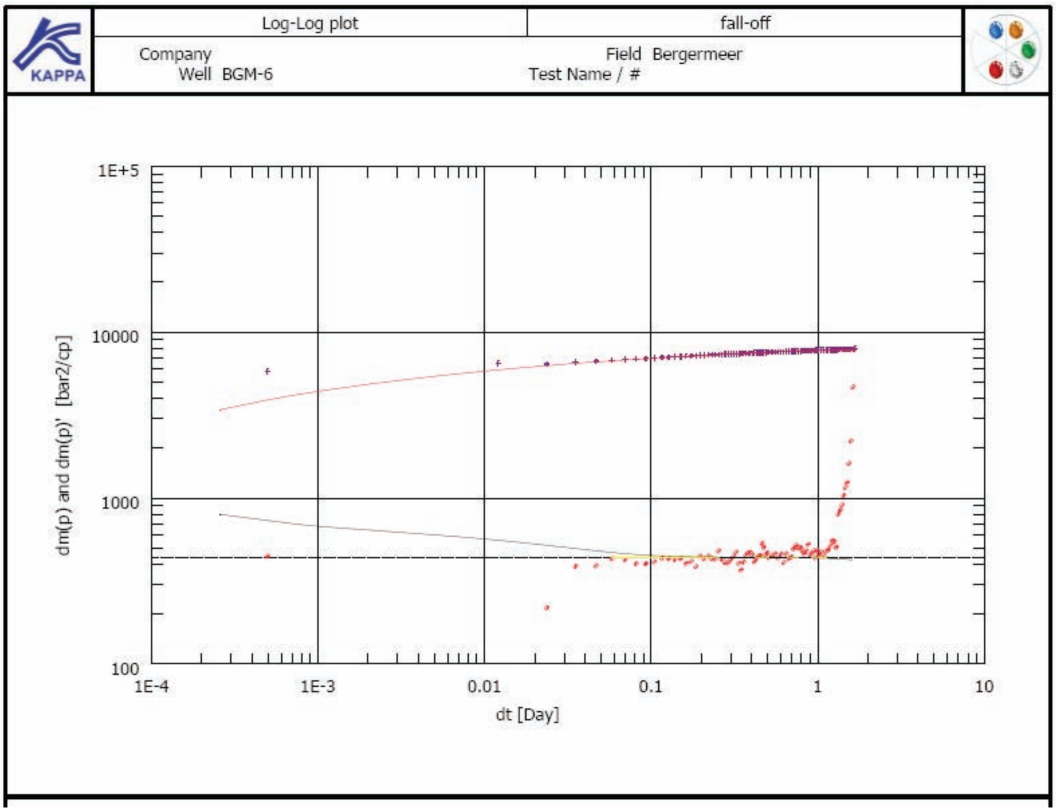


Figure 7-2 BGM-6 log-log plot of fall-off period

KAPPA	Main Results	fall-off
	Company Well BGM-6	Field Bergermeer Test Name / #

Test date / time	16-07-07 / 27-08-07
Formation interval	
Perforated interval	
Gauge type / #	BHP #75586
Gauge depth	
TEST TYPE	Standard
Porosity Phi (%)	10
Well Radius rw	0.127 m
Pay Zone h	120 m
Water Salt (ppm)	10000
Form. compr.	3E-6 psi-1
Reservoir T	86 °C
Reservoir P	10 bara
FLUID TYPE	Gas
Gas Gravity	0.6
Pseudo-Critical P	46.6875 bara
Pseudo-Critical T	351.93 °R
Sour gas composition	
Hydrogen sulphide	0
Carbon dioxide	0
Nitrogen	0
Temperature	86 °C
Pressure	10 bara
Properties	@ Reservoir T&P
Gas	
Z	0.989383
Mug	0.0136338 cp
Bg	0.124631 cf/scf
cg	0.00696739 psi-1
Rhog	0.00589638 g/cc
Total Compr. ct	0.00697039 psi-1
Connate Water (%)	0
Selected Model	
Model Option	Standard Model
Well	Vertical - Limited entry
Reservoir	Homogeneous
Boundary	Parallel faults
Main Model Parameters	
TMatch	1.07E+5 [Day]-1
PMatch	0.00114 [bar2/cp]-1
C	0.82 m3/bar
Total Skin	1.96
k.h, total	22400 md.m
k, average	187 md
Pi	10.0151 bara

Model Parameters	
Well & Wellbore parameters (BGM-6)	
C	0.82 m3/bar
Skin	-0.4
Geometrical Skin	2.36
hw	80 m
Zw	65 m
Reservoir & Boundary parameters	
h	120 m
Pi	10.0151 bara
k.h	22400 md.m
k	187 md
kz/kr	1
S - No flow	350 m
N - No flow	700 m
Derived & Secondary Parameters	
Delta P (Total Skin)	1.20705 bar
Delta P Ratio (Total Skin)	0.276938 Fraction

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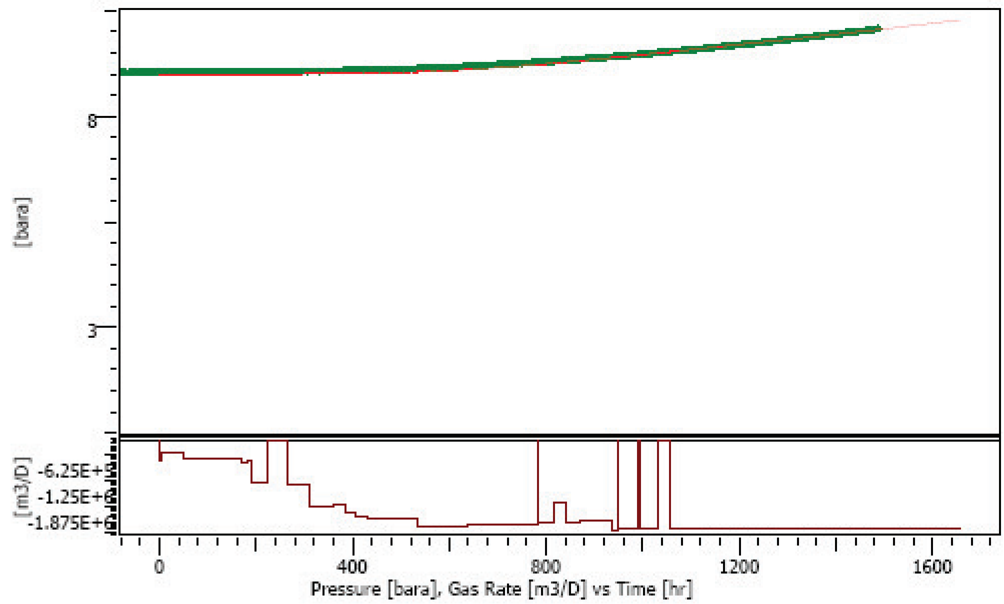
Figure 7-3 Main results BGM-6 fall-off test.

History plot	Analysis 1
Company Well BGM-5	Field Bergermeer Test Name / #



BGM5_76760_76391 injection #6
Rate -2.107E+6 m3/D
Rate change 2.107E+6 m3/D
P@dt=0 9.534 bara
Pi 9 bara
Smoothing 0.1

Selected Model
Model Option Standard Model
Well Vertical
Reservoir Homogeneous
Boundary Parallel faults

Main Model Parameters
TMatch 3.27E-4 [hr]-1
PMatch 2.37E-4 [bar2/cp]-1
C 0.82 m3/bar
Phi 0.225
Phi.h 29.7 m
k.h, total 23500 md.m
k, average 178 md
Pi 9 bara
Well distance 750 m

Model Parameters
Well & Wellbore parameters (Active well)
C 0.82 m3/bar
Skin 0.539
Reservoir & Boundary parameters
Pi 9 bara
k.h 23500 md.m
k 178 md
Phi 0.225
Phi.h 29.7 m
S - No flow 350 m
N - No flow 700 m

Derived & Secondary Parameters

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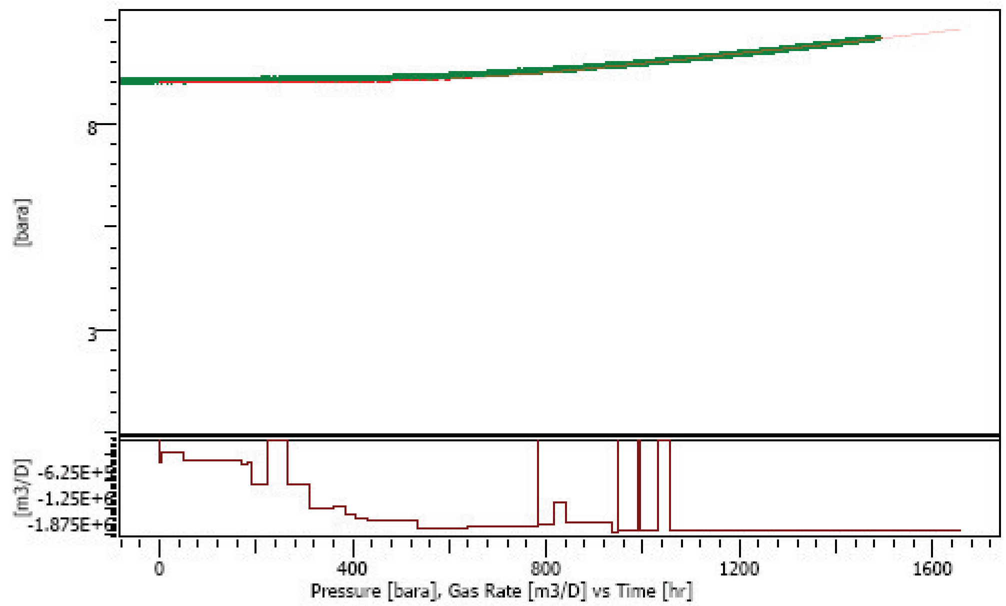
Figure 7-4 BGM-5 interpretation injection period after 2nd gauge retrieval, well distance 750.

KAPPA	History plot	Analysis 7
	Company Well BGM-5	Field Bergermeer Test Name / #



BGM5_76760_76391 injection #6

Rate	-2.107E+6 m3/D
Rate change	2.107E+6 m3/D
P@dt=0	9.534 bara
Pi	9 bara
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Parallel faults

Main Model Parameters

TMatch	2.63E-4 [hr]-1
PMatch	1.01E-4 [bar2/cp]-1
C	0.82 m3/bar
Phi	0.269
Phi.h	35.5 m
k.h, total	10000 md.m
k, average	75.9 md
Pi	9 bara
Well distance	500 m

Model Parameters

Well & Wellbore parameters (Active well)

C	0.82 m3/bar
Skin	0.539

Reservoir & Boundary parameters

Pi	9 bara
k.h	10000 md.m
k	75.9 md
Phi	0.269
Phi.h	35.5 m
S - No flow	350 m
N - No flow	750 m

Derived & Secondary Parameters

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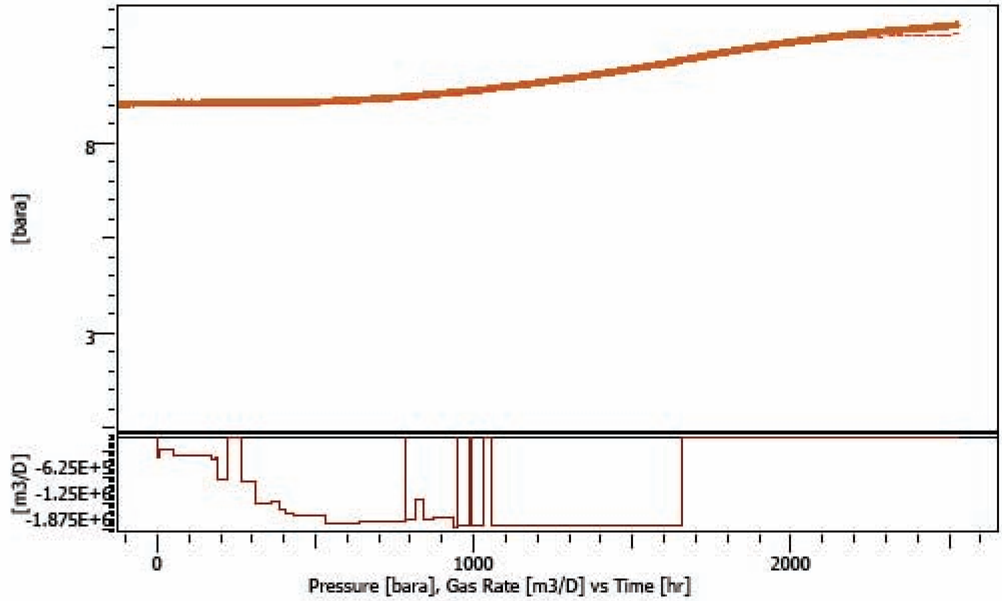
Figure 7-5 BGM-5 interpretation injection period after 2nd gauge retrieval, well distance 500m.

History plot	Analysis 2
Company Well BGM-5	Field Bergermeer Test Name / #



BGM5_76760_76391_76799 injection #6

Rate	-2.107E+6 m3/D
Rate change	2.107E+6 m3/D
P@dt=0	9.4284 bara
Pi	9 bara
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Parallel faults

Main Model Parameters

TMatch	2.81E-4 [hr]-1
PMatch	1.76E-4 [bar2/cp]-1
C	0.8 m3/bar
Phi	0.217
Phi.h	28.6 m
k.h, total	17400 md.m
k, average	132 md
Pi	9 bara
Well distance	710 m

Model Parameters

Well & Wellbore parameters (Active well)

C	0.8 m3/bar
Skin	0.539

Reservoir & Boundary parameters

Pi	9 bara
k.h	17400 md.m
k	132 md
Phi	0.217
Phi.h	28.6 m
S - No flow	350 m
N - No flow	700 m

Derived & Secondary Parameters

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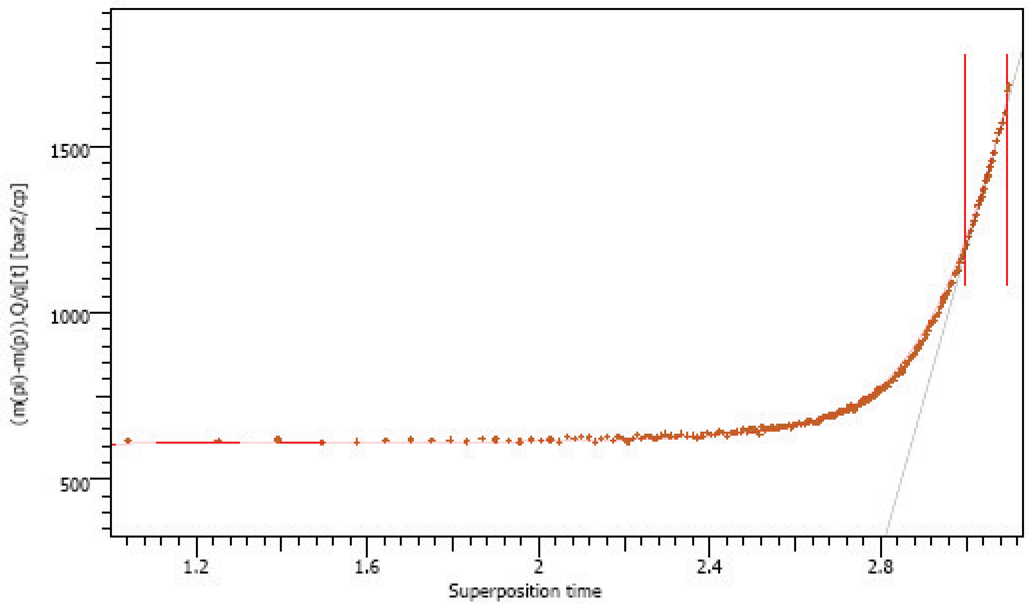
Figure 7-6 **BGM-5 interpretation injection period after 3rd gauge retrieval, well distance 710m, parallel faults.**

Semi-Log plot	Analysis 2
Company Well BGM-5	Field Bergermeer Test Name / #



BGM5_76760_76391_76799 injection #6	
Rate	-2.107E+6 m3/D
Rate change	2.107E+6 m3/D
P@dt=0	9.4284 bara
Pi	9 bara
Smoothing	0.1
Selected Model	
Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Parallel faults
Main Model Parameters	
TMatch	2.81E-4 [hr]-1
PMatch	1.76E-4 [bar2/cp]-1
C	0.8 m3/bar
Phi	0.217
Phi.h	28.6 m
k.h, total	17400 md.m
k, average	132 md
Pi	9 bara
Well distance	710 m

Model Parameters	
Well & Wellbore parameters (Active well)	
C	0.8 m3/bar
Skin	0.539
Reservoir & Boundary parameters	
Pi	9 bara
k.h	17400 md.m
k	132 md
Phi	0.217
Phi.h	28.6 m
S - No flow	350 m
N - No flow	700 m
Derived & Secondary Parameters	
Semilog Line (BGM5_76760_76391_76799 injection #6)	
From	1415.6 hr
To	1639.57 hr
Slope	4558.65 bar2/cp
M(p)@1hr	-6118.93 bar2/cp
PMatch	2.52E-4 [bar2/cp]-1
k.h	25000 md.m
k	190 md
Phi	0.108

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Figure 7-7 Semi-log BGM-5 interpretation injection period after 3rd gauge retrieval.

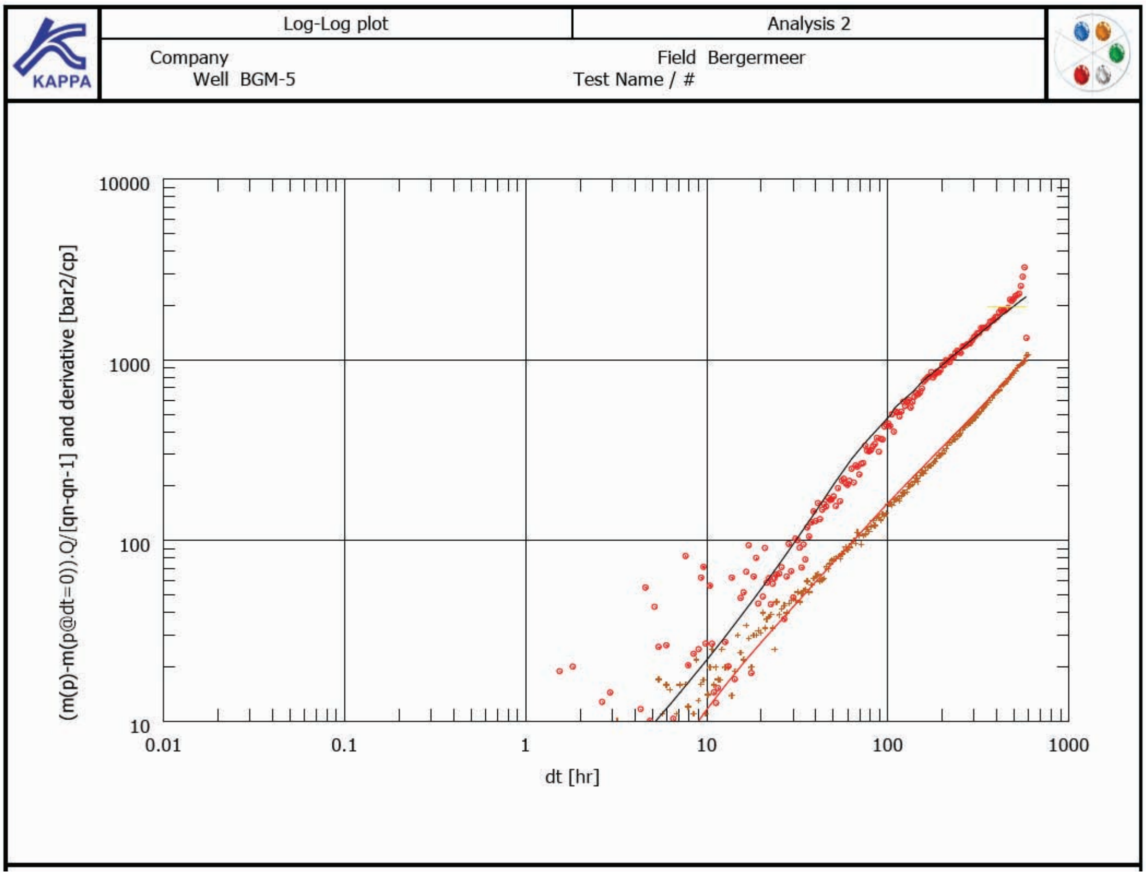
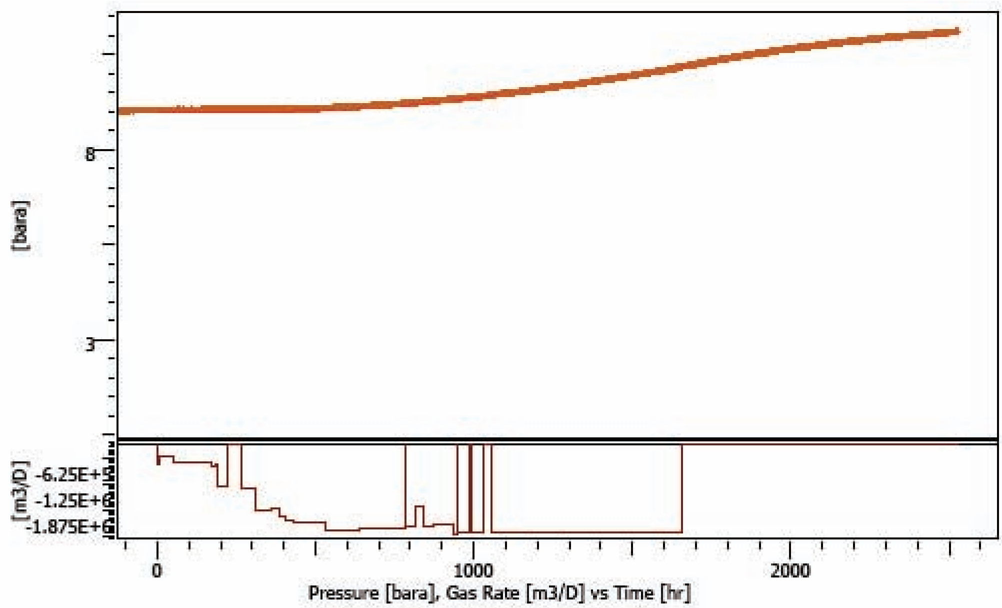


Figure 7-8 **Log-log BGM-5 interpretation injection period after 3rd gauge retrieval, results KH 17400 mD*m, k 132 mD, phi 21.7%.**

History plot	Analysis 1
Company Well BGM-5	Field Bergermeer Test Name / #



BGM5_76760_76391_76799 fall-off #6

Rate	0 m3/D
Rate change	2.107E+6 m3/D
P@dt=0	10.1728 bara
Pi	9 bara
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Main Model Parameters

TMatch	2.83E-4 [hr]-1
PMatch	1.8E-4 [bar2/cp]-1
C	0.82 m3/bar
Phi	0.22
Phi.h	29 m
k.h, total	17800 md.m
k, average	135 md
Pi	9 bara
Well distance	710 m

Model Parameters
Well & Wellbore parameters (Active well)

C	0.82 m3/bar
Skin	0.539

Reservoir & Boundary parameters

Pi	9 bara
k.h	17800 md.m
k	135 md
Phi	0.22
Phi.h	29 m
S - No flow	350 m
E - No flow	700 m
N - No flow	700 m
W - No flow	1000 m

Derived & Secondary Parameters

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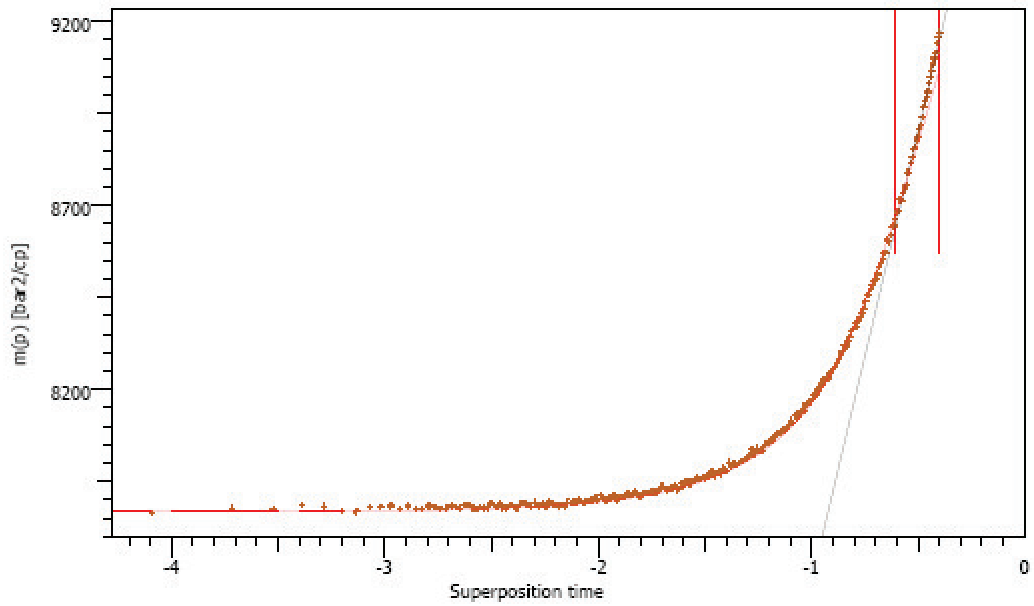
Figure 7-9 BGM-5 interpretation shut-in period after 3rd gauge retrieval, closed compartment.

Semi-Log plot	Analysis 1
Company	Field Bergermeer
Well BGM-5	Test Name / #



BGM5_76760_76391_76799 fall-off #6

Rate	0 m3/D
Rate change	2.107E+6 m3/D
P@dt=0	10.1728 bara
Pi	9 bara
Smoothing	0.1

Selected Model

Model Option	Standard Model
Well	Vertical
Reservoir	Homogeneous
Boundary	Rectangle, No flow

Main Model Parameters

TMatch	2.83E-4 [hr]-1
PMatch	1.8E-4 [bar2/cp]-1
C	0.82 m3/bar
Phi	0.22
Phi.h	29 m
k.h, total	17800 md.m
k, average	135 md
Pi	9 bara
Well distance	710 m

Model Parameters

Well & Wellbore parameters (Active well)

C	0.82 m3/bar
Skin	0.539

Reservoir & Boundary parameters

Pi	9 bara
k.h	17800 md.m
k	135 md
Phi	0.22
Phi.h	29 m
S - No flow	350 m
E - No flow	700 m
N - No flow	700 m
W - No flow	1000 m

Derived & Secondary Parameters

Semilog Line (BGM5_76760_76391_76799 fall-off #6)

From	2078.05 hr
To	2495.82 hr
Slope	2451.13 bar2/cp
Intercept	10128.3 bar2/cp
M(p)@1hr	2526.38 bar2/cp
PMatch	4.7E-4 [bar2/cp]-1
k.h	46600 md.m
k	353 md
p*	11.6536 bara
Phi	3.4E-5

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Figure 7-10 Semi-log plot BGM-5 shut-in period after 3rd gauge retrieval, closed compartment.

7.2 Welltest interpretation results

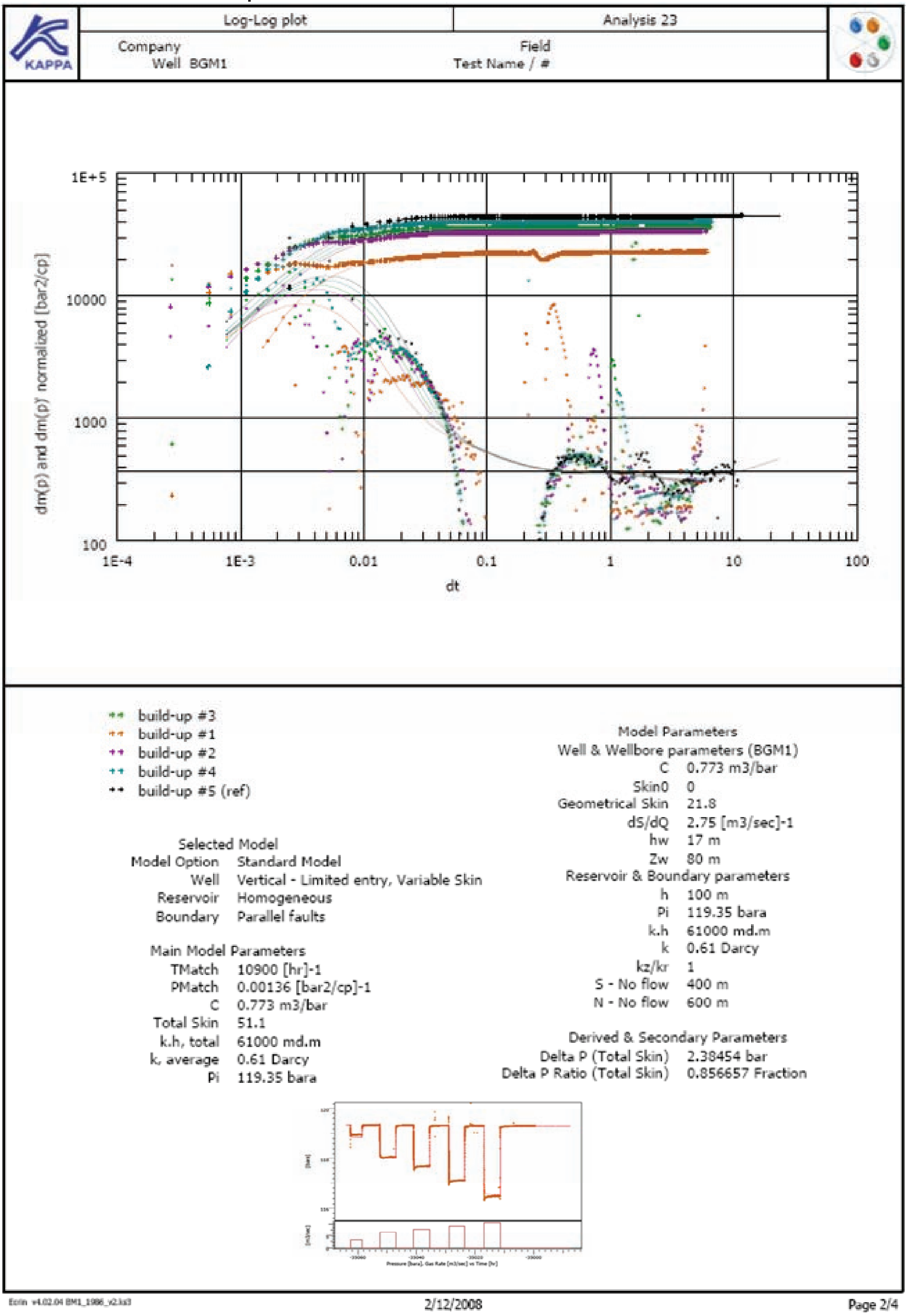
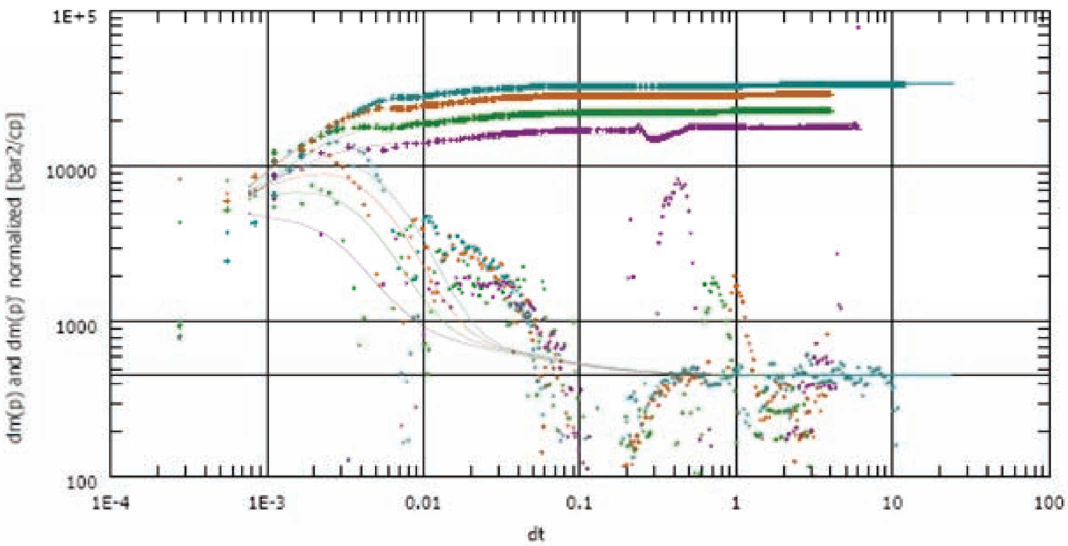


Figure 7-11 **BGM1 1986, partial penetration model, log-log plot build-ups.**

KAPPA	Log-Log plot	new_match
	Company Well BGM1	Field Test Name / # 1987



build-up #2
build-up #3
build-up #1
build-up #4 (ref)

Selected Model

Model Option	Standard Model
Well	Vertical - Limited entry, Variable Skin
Reservoir	Homogeneous
Boundary	Infinite

Main Model Parameters

TMatch	13300 [hr]-1
PMatch	0.00108 [bar2/cp]-1
C	0.5 m3/bar
Total Skin	28.7
k.h, total	48000 md.m
k, average	0.48 Darcy
Pi	115.9 bara

Model Parameters

Well & Wellbore parameters (BGM1)

C	0.5 m3/bar
Skin0	1
Geometrical Skin	3.57
dS/dQ	2.3 [m3/sec]-1
hw	60 m
Zw	60 m

Reservoir & Boundary parameters

h	100 m
Pi	115.9 bara
k.h	48000 md.m
k	0.48 Darcy
kz/kr	0.5

Derived & Secondary Parameters

Rinv	670 m
Test. Vol.	14.0982 MMm3
Delta P (Total Skin)	1.70962 bar
Delta P Ratio (Total Skin)	0.768671 Fraction

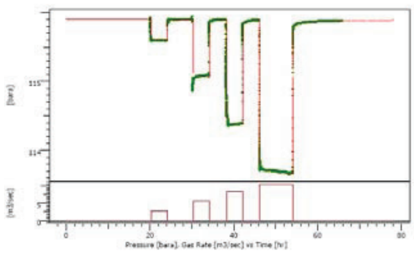


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Figure 7-12 BGM-1, 1987, partial penetration model, log-log plot build-ups.

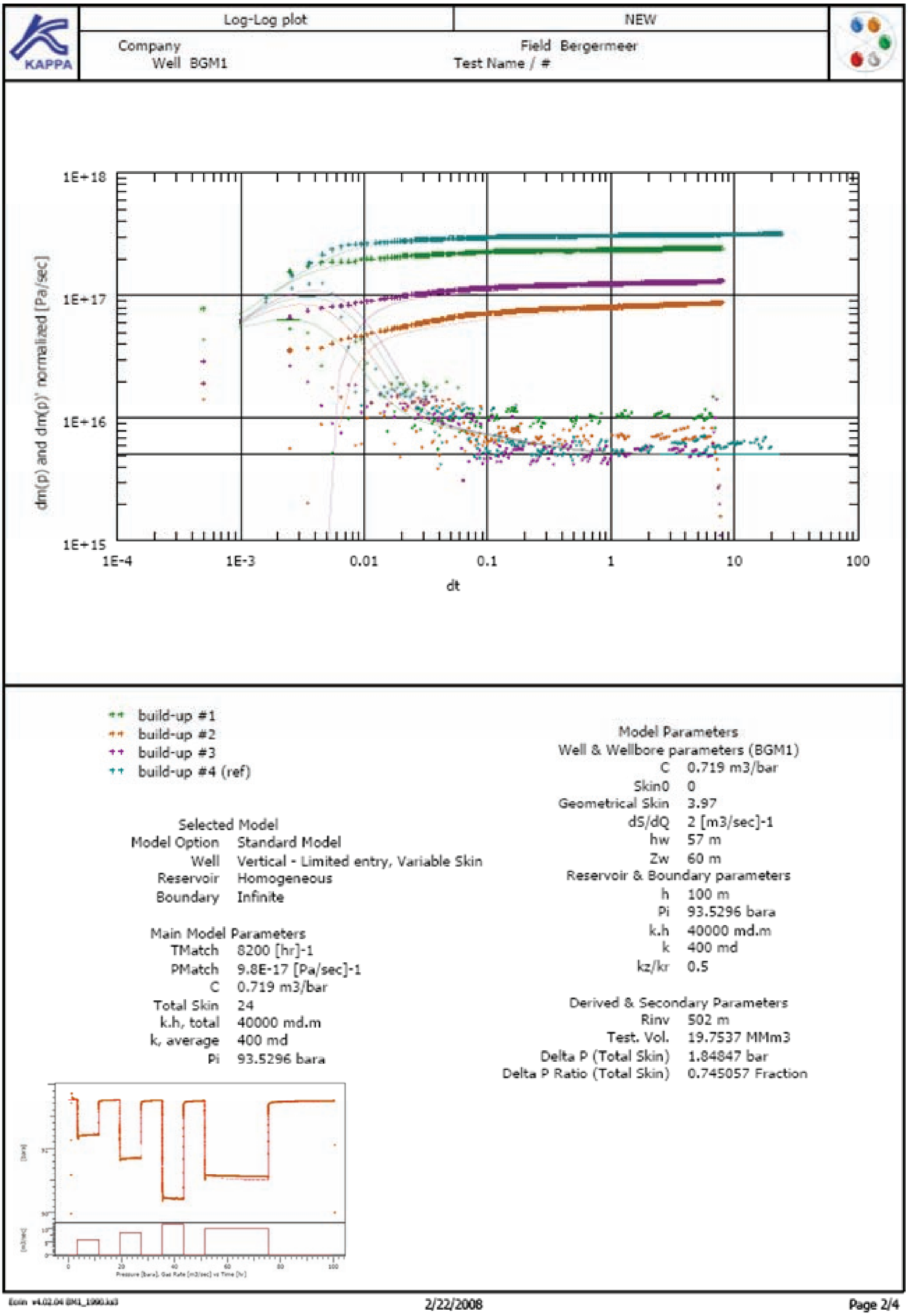


Figure 7-13 BGM-1, 1990, partial penetration model, log-log plot build-ups.

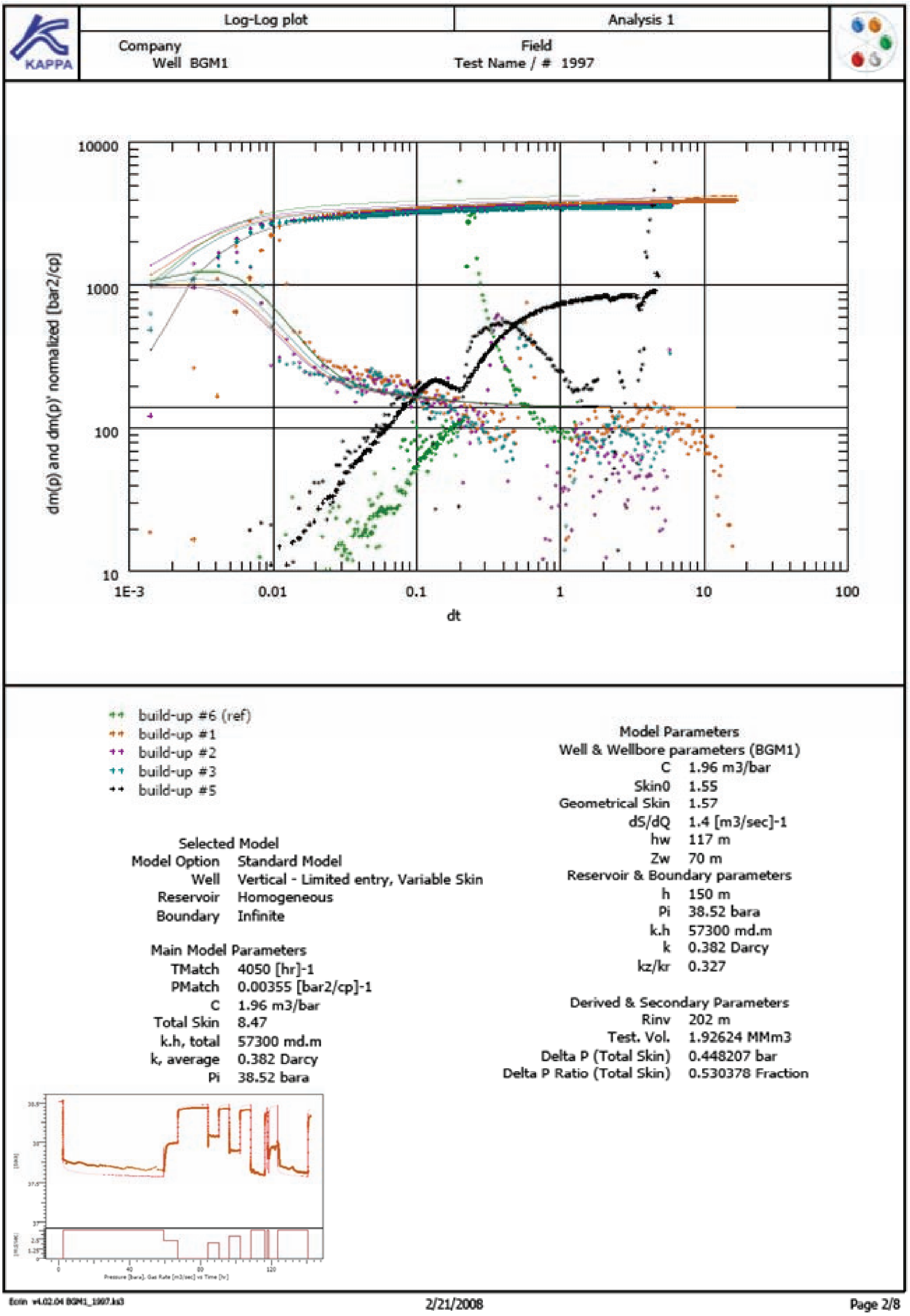


Figure 7-14 BGM-1, 1997, partial penetration model, log-log plot build-ups.

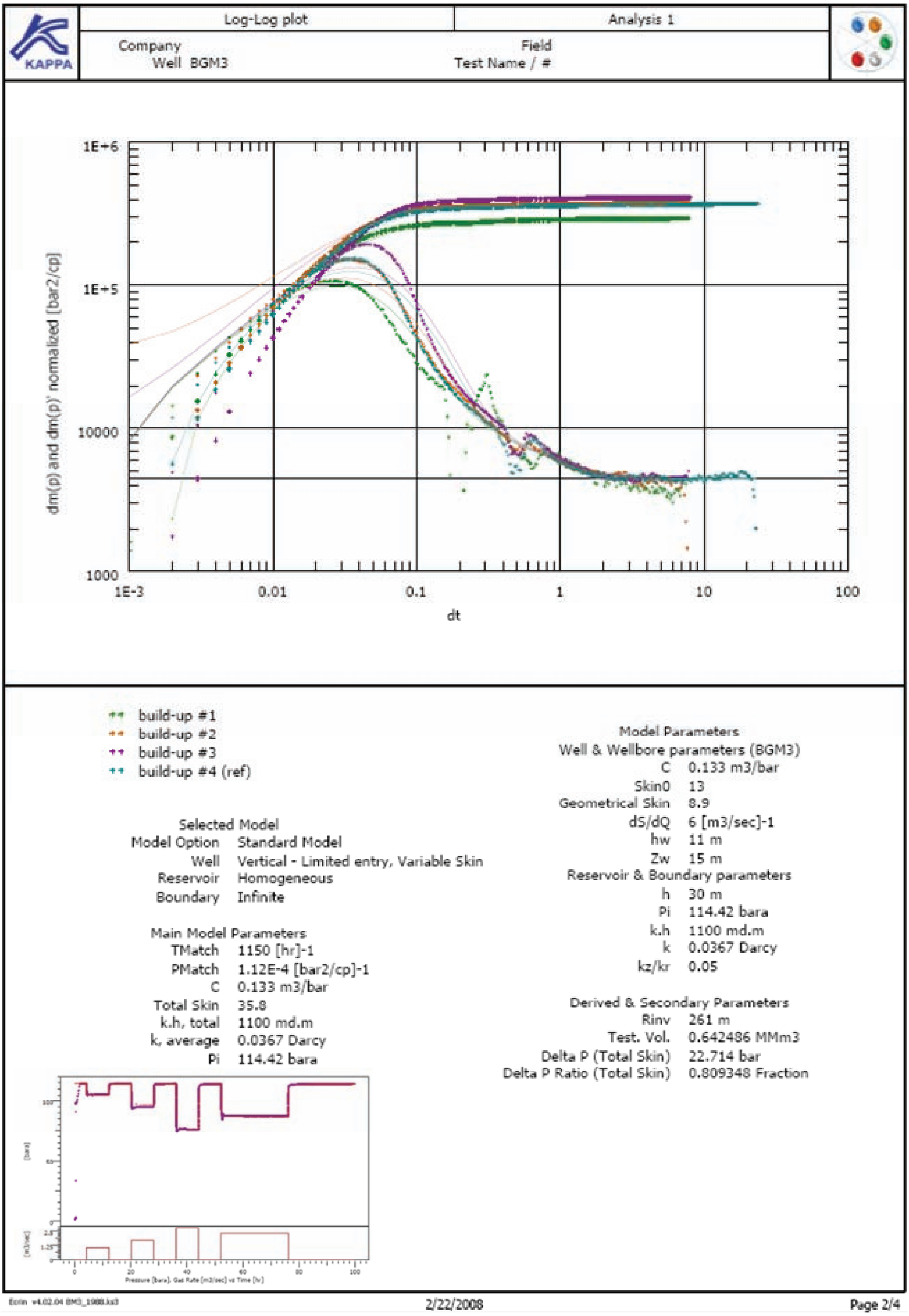


Figure 7-15 **BGM-3A, 1988, partial penetration model, log-log plot build-ups.**

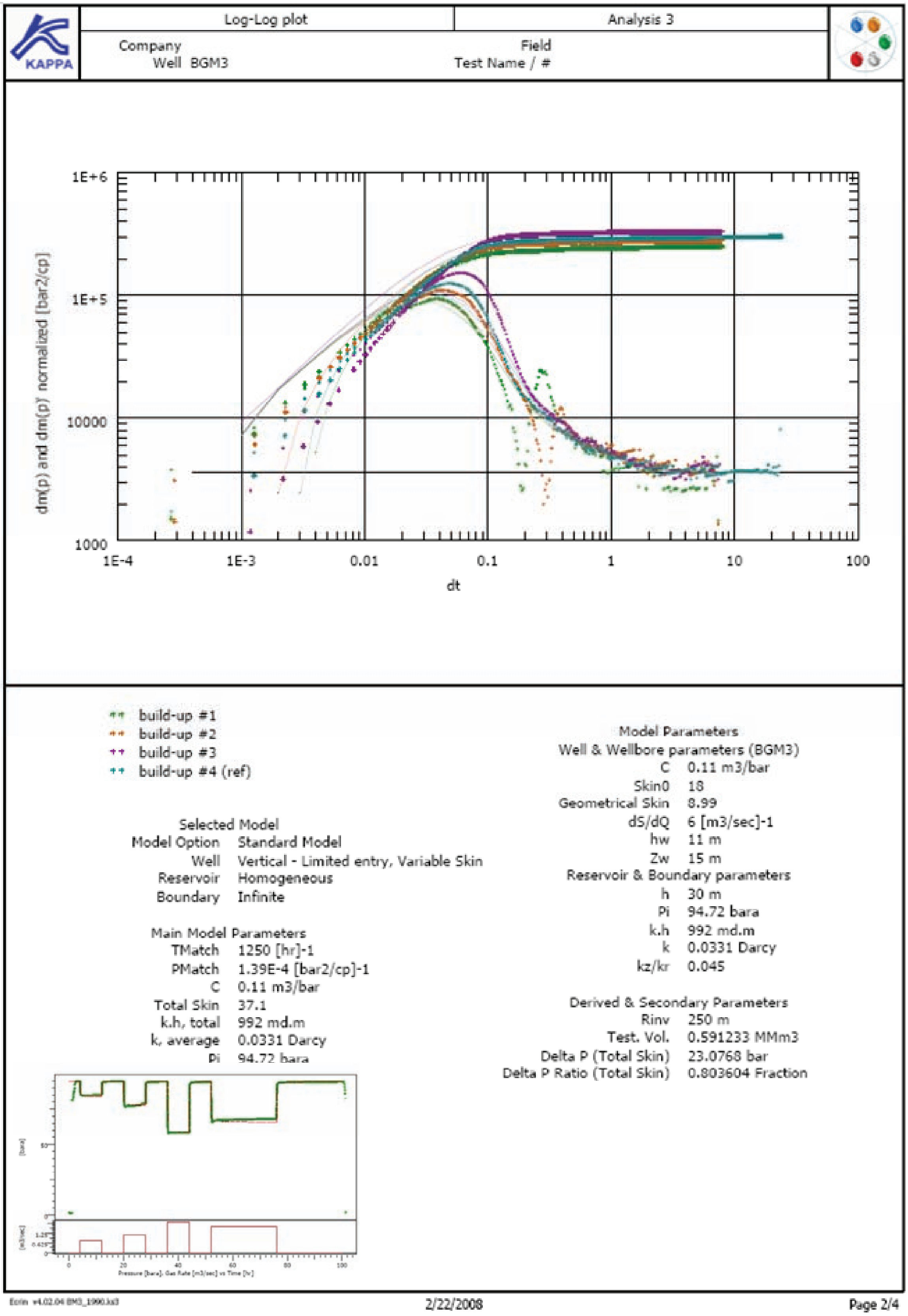


Figure 7-16 BGM-3A, 1990, partial penetration model, log-log plot build-ups.

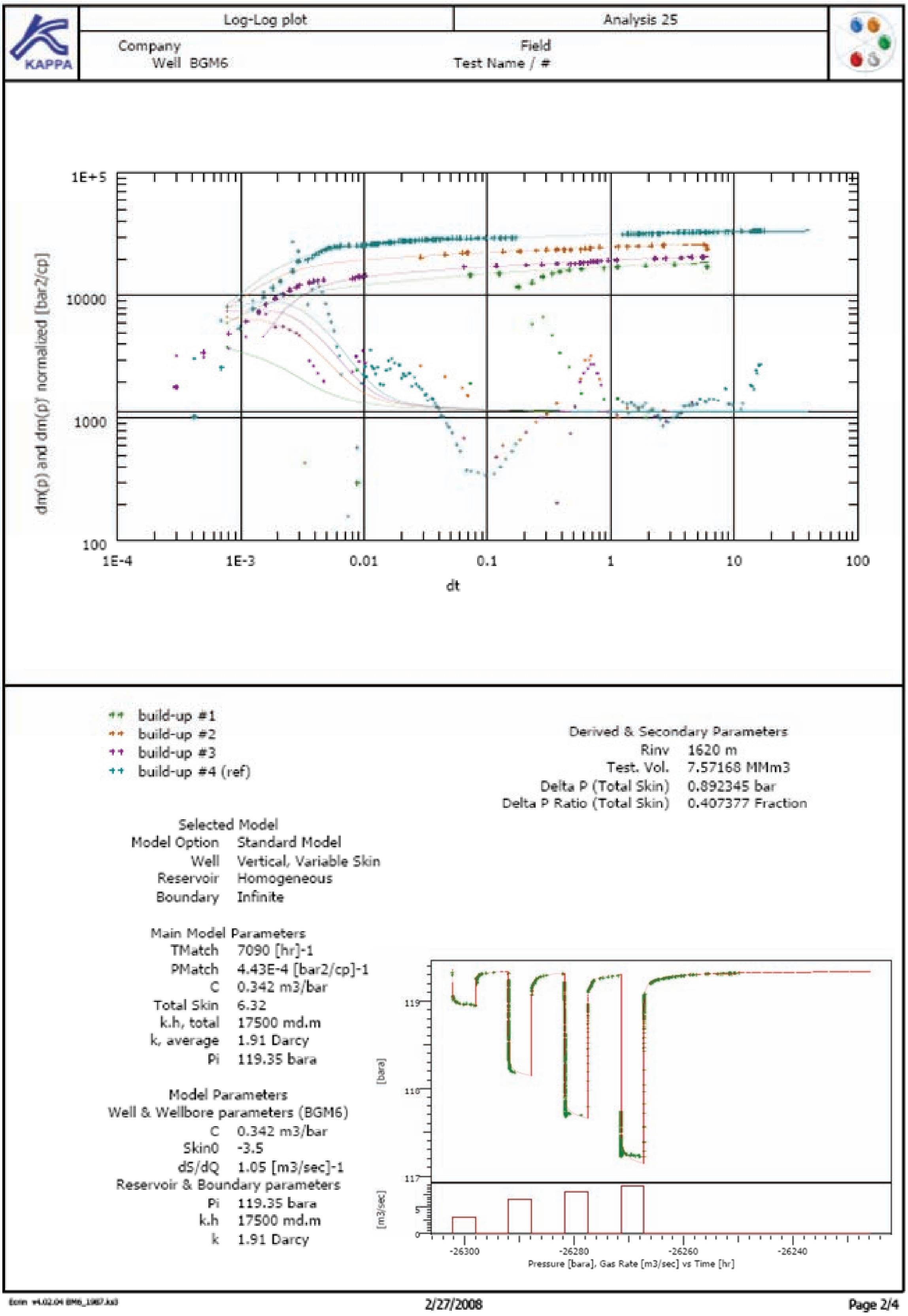
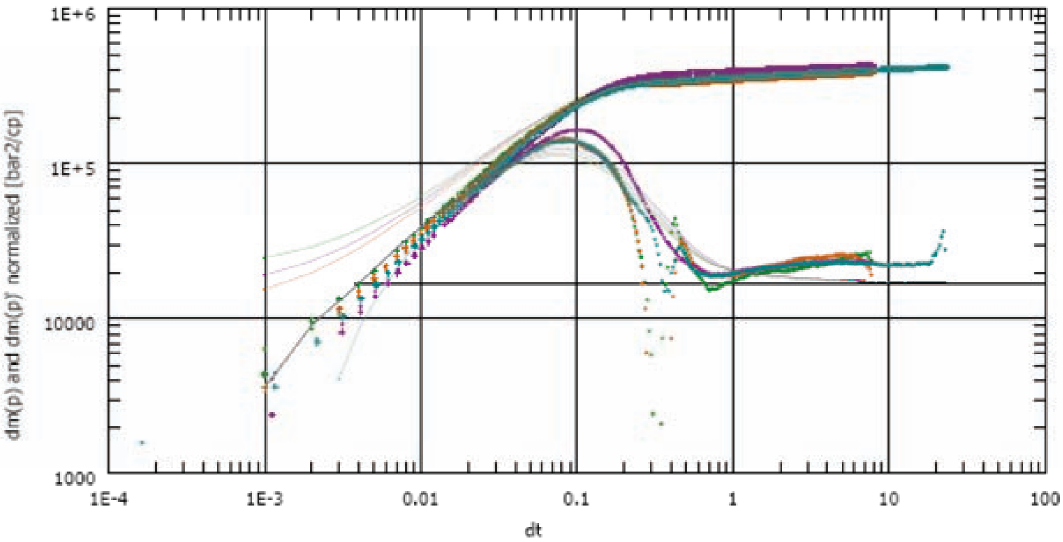


Figure 7-17 BGM-6A, 1987, vertical homogeneous model, log-log plot build-ups.

Log-Log plot	match
Company Well BGM7	Field Test Name / # 1990



build-up #1
build-up #2
build-up #3
build-up #4 (ref)

Derived & Secondary Parameters

Rinv	86.5 m
Test. Vol.	0.154239 MMm3
Delta P (Total Skin)	14.9873 bar
Delta P Ratio (Total Skin)	0.442025 Fraction

Selected Model

Model Option	Standard Model
Well	Vertical, Variable Skin
Reservoir	Homogeneous
Boundary	Infinite

Main Model Parameters

TMatch	133 [hr]-1
PMatch	2.94E-5 [bar2/cp]-1
C	0.276 m3/bar
Total Skin	6.14
k.h, total	266 md.m
k, average	0.00709 Darcy
Pi	109.24 bara

Model Parameters
Well & Wellbore parameters (BGM7)

C	0.276 m3/bar
Skin0	4
dS/dQ	1 [m3/sec]-1

Reservoir & Boundary parameters

Pi	109.24 bara
k.h	266 md.m
k	0.00709 Darcy

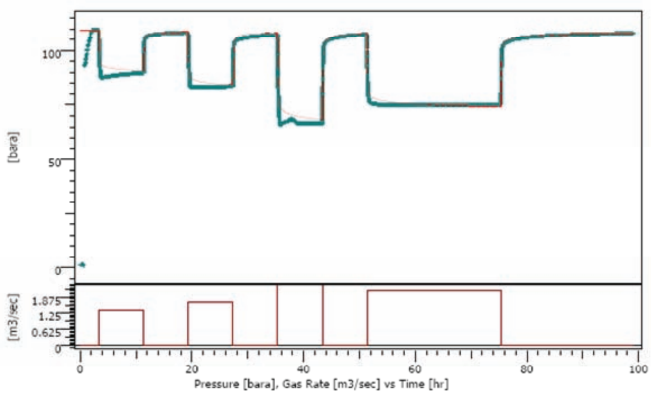


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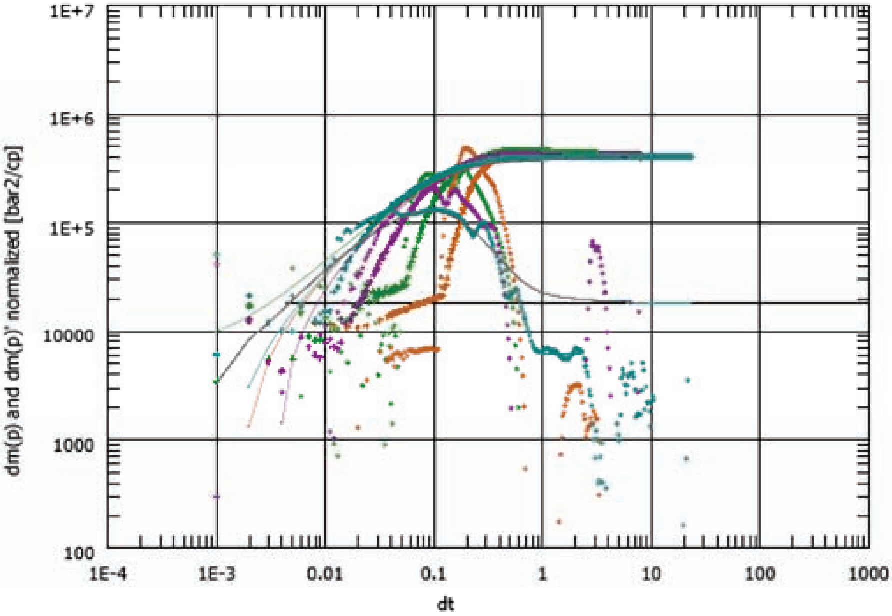
Figure 7-18 BGM-7, 1990, vertical homogeneous model, log-log plot build-ups.

Log-Log plot	Analysis 21
Company Well BGM7	Field Test Name / # 1990



production #1
production #2
production #3
production #4 (ref)

Selected Model
Model Option Standard Model
Well Vertical
Reservoir Homogeneous
Boundary Infinite

Main Model Parameters
TMatch 116 [hr]-1
PMatch 2.78E-5 [bar2/cp]-1
C 0.3 m3/bar
Total Skin 6
k.h, total 251 md.m
k, average 0.00669 Darcy
Pi 109.244 bara

Model Parameters
Well & Wellbore parameters (BGM7)
C 0.3 m3/bar
Skin 6
Reservoir & Boundary parameters
Pi 109.244 bara
k.h 251 md.m
k 0.00669 Darcy

Derived & Secondary Parameters
Rinv 84.6 m
Test. Vol. 0.147596 MMm3
Delta P (Total Skin) 15.5606 bar
Delta P Ratio (Total Skin) 0.43706 Fraction

Semilog Line (BERGERM7 production #4)
From 52.3201 hr
To 53.5521 hr
Slope 14164.4 bar2/cp
M(p)@1hr 4.05919E+5 bar2/cp
PMatch 8.13E-5 [bar2/cp]-1
k.h 734 md.m
k 0.0196 Darcy
Skin 28.7
Delta P Skin 47.4293 bar

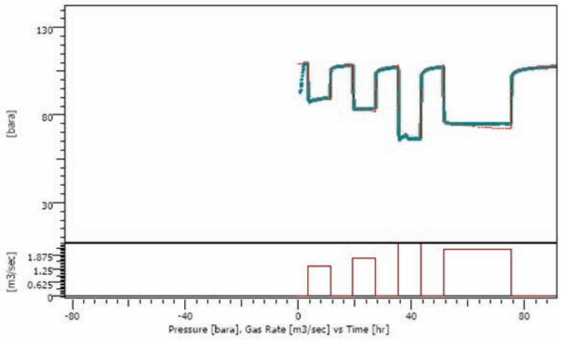


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Figure 7-19 BGM-7, 1990, vertical homogeneous model, log-log plot and semi-log results drawdowns.

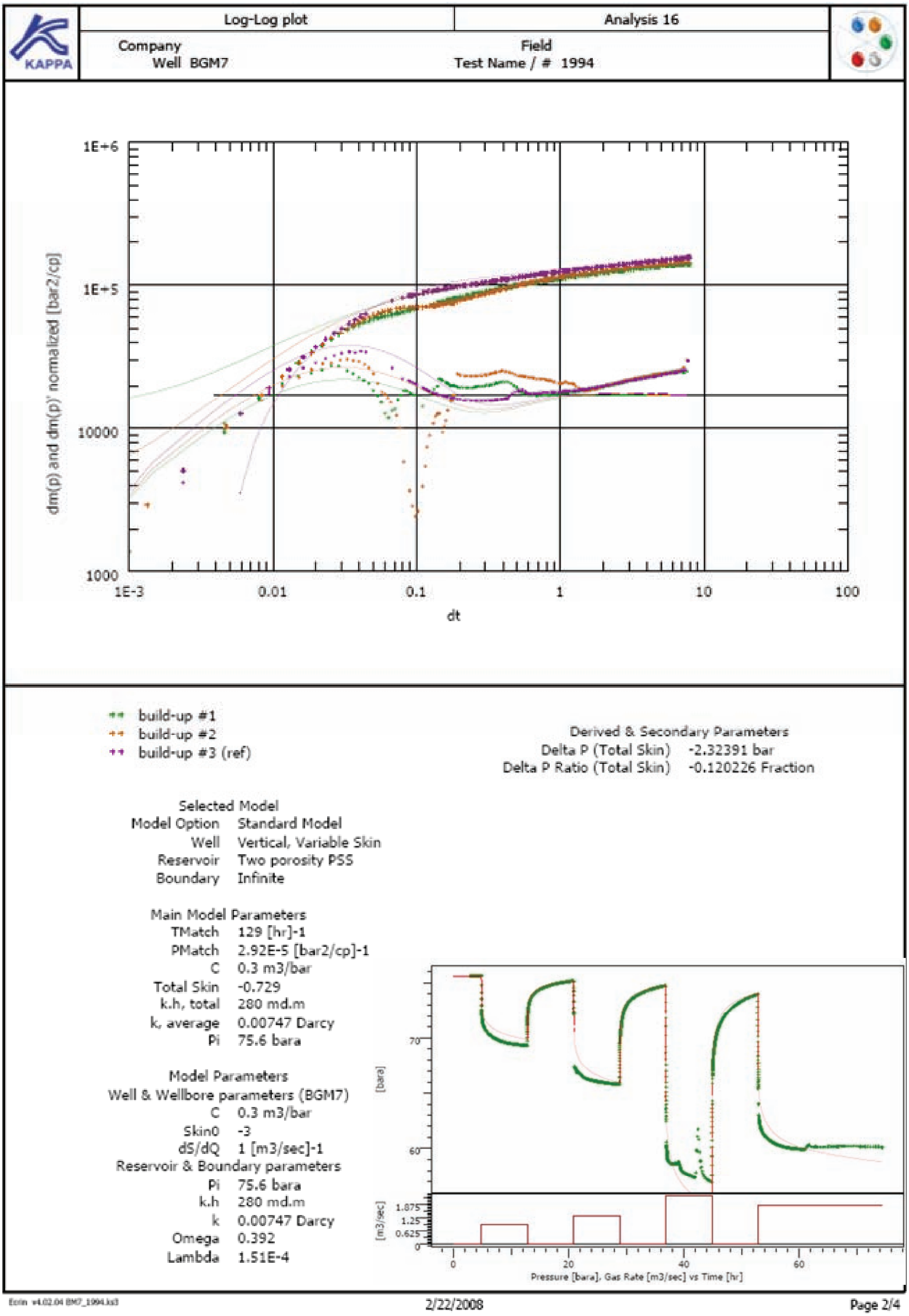

Figure 7-20 BGM-7, 1994, vertical homogeneous model, log-log plot build-ups.

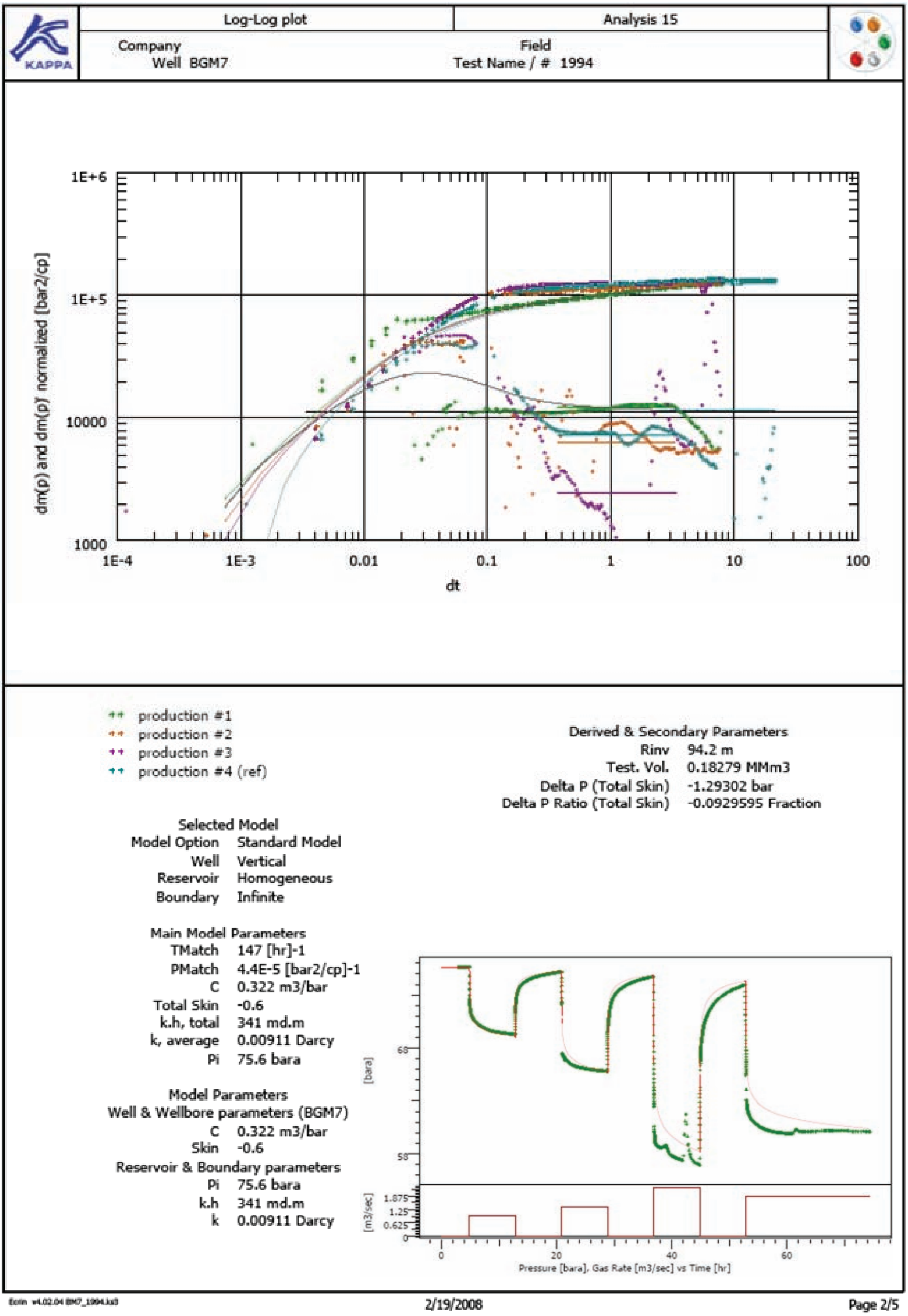

Figure 7-21 BGM-7, 1994 , vertical homogeneous model, log-log plot drawdowns.

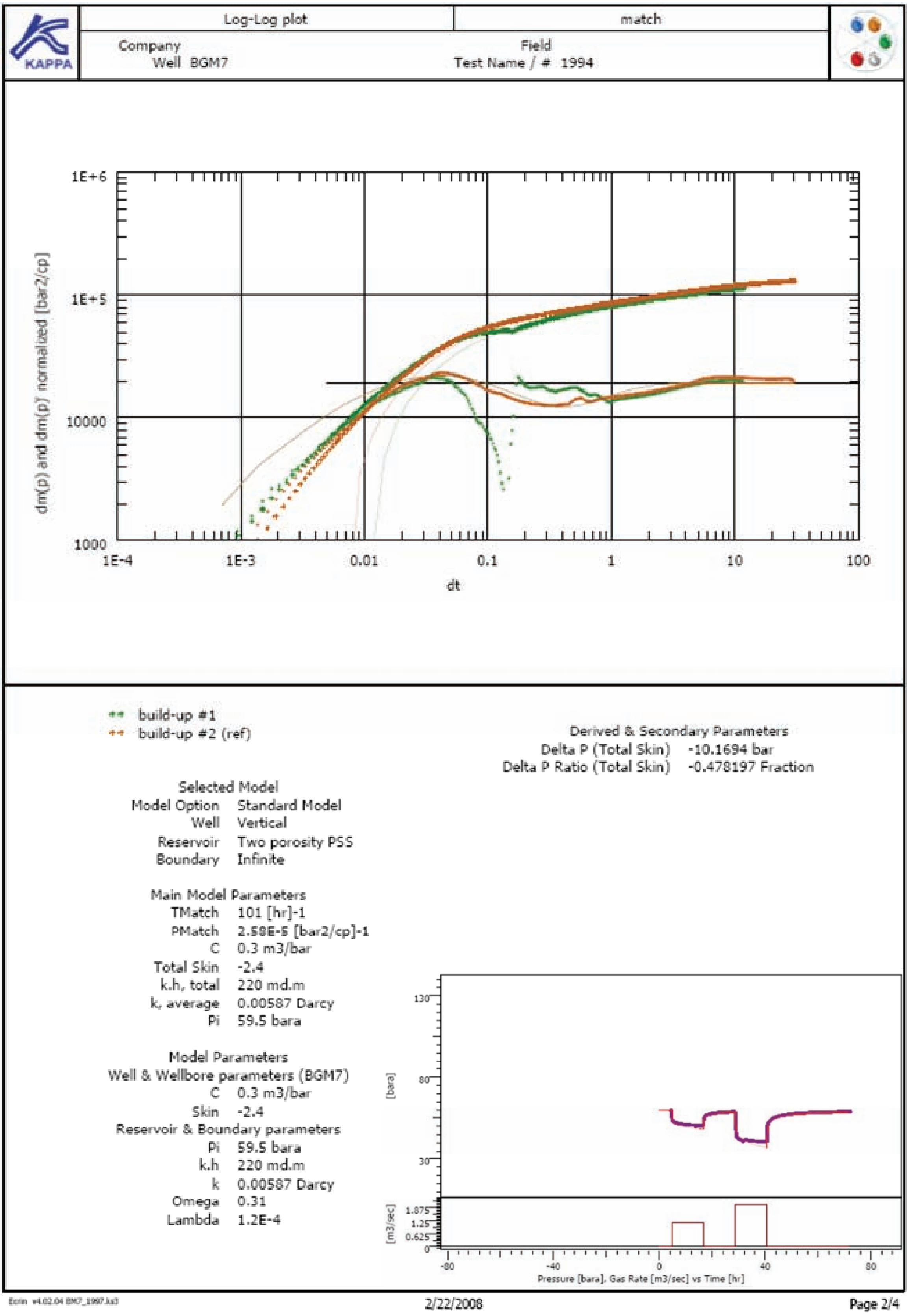

Figure 7-22 BGM-7, 1997, vertical homogeneous model, log-log plot build-ups.

7.3 Production Performance Curves

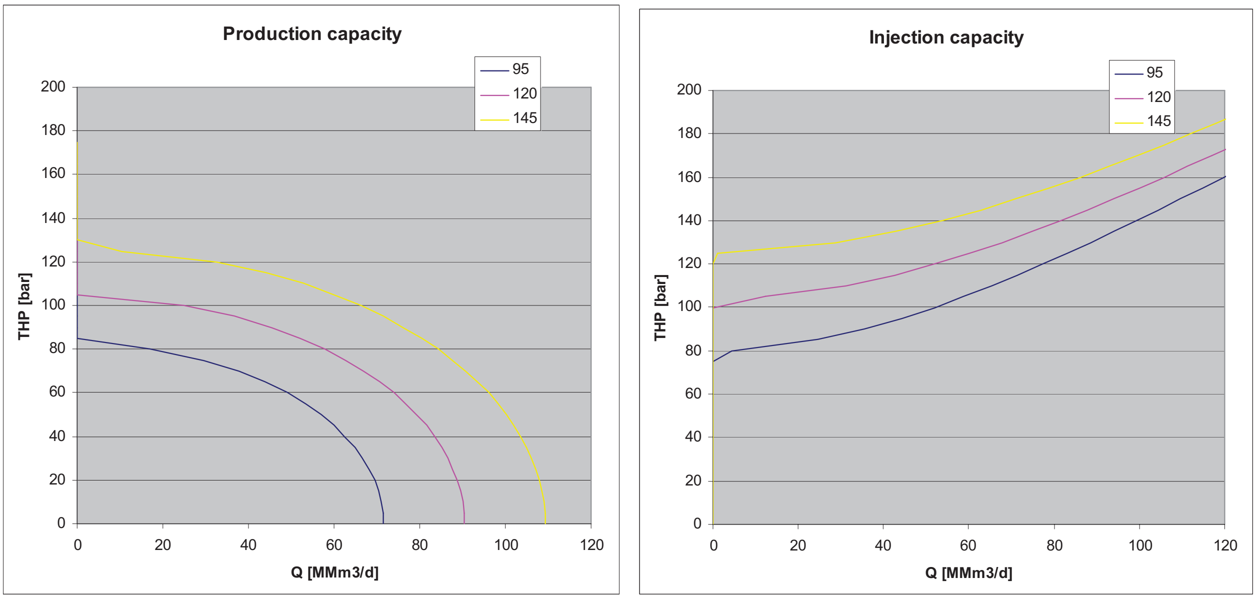

Figure 7-23 Field performance low case (BELL_033_ALT_H06_H11), Large offtake (20 wells).

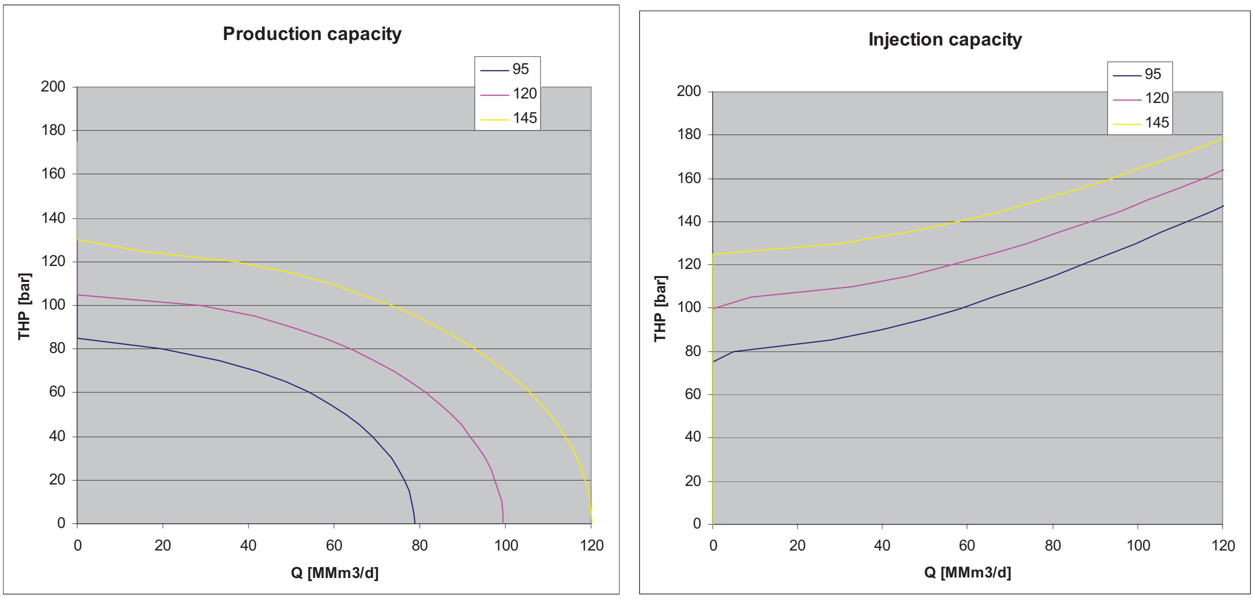

Figure 7-24 Field performance mid case (BELL_050_ ALT_H06_H11), Large offtake (20 wells).

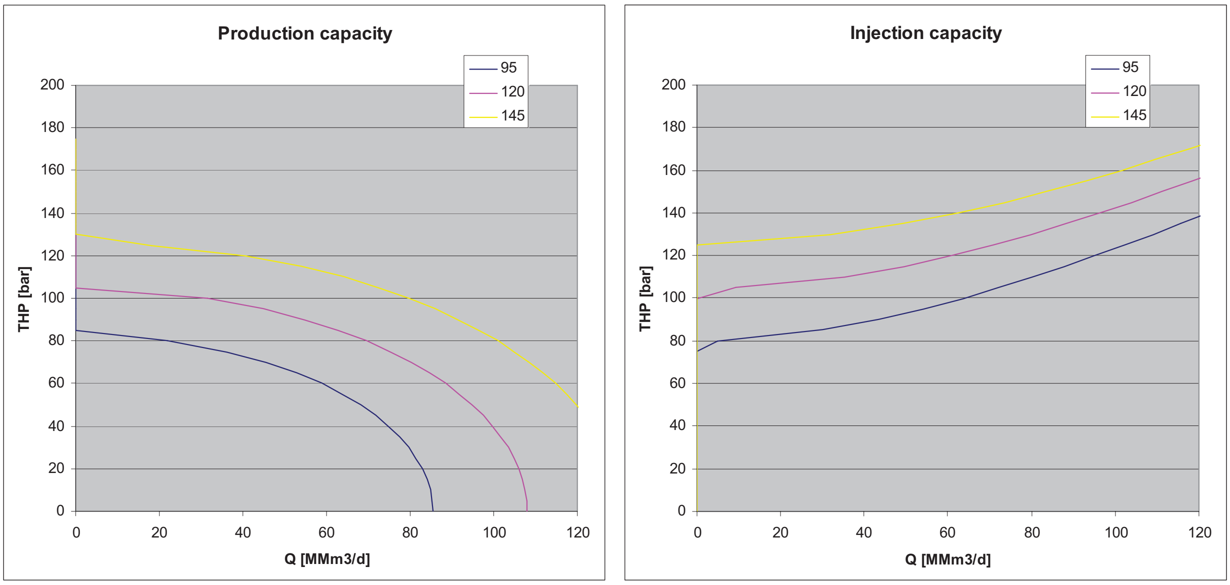

Figure 7-25 Field performance high case (DISMIDHIGHKV_H06_H11), Large offtake (20 wells).

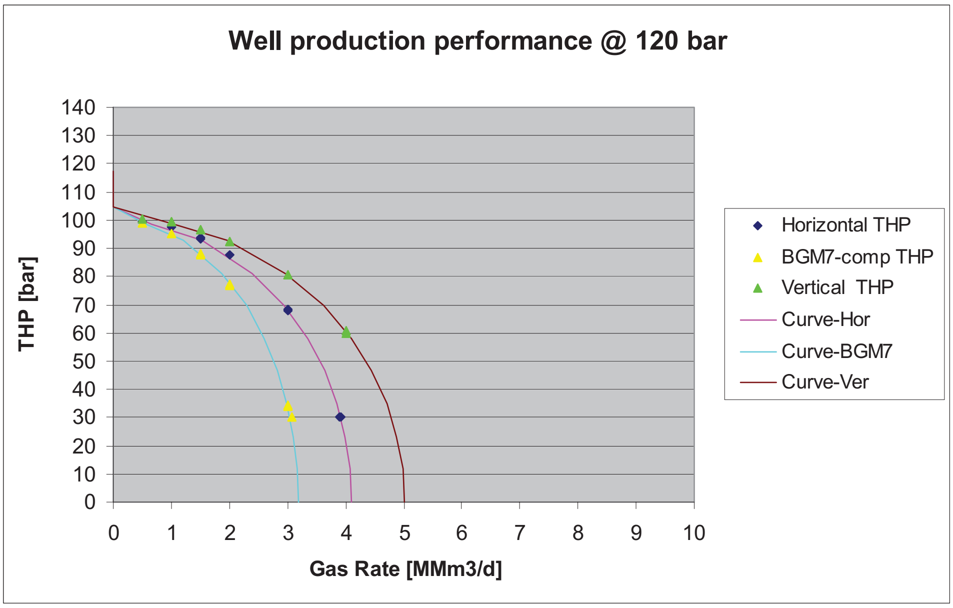

Figure 7-26 Well production performance low case (BELL_033_H06_H11),), 7 5/8” Tbg’s.

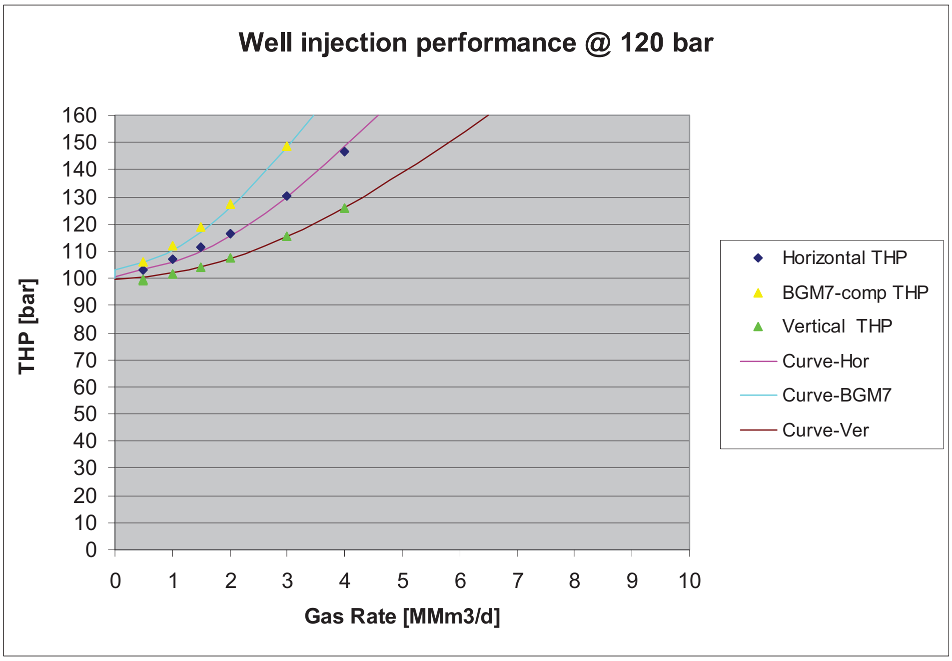

Figure 7-27 Well injection performance low case (BELL_033_H06_H11),), 7 5/8” Tbg’s.

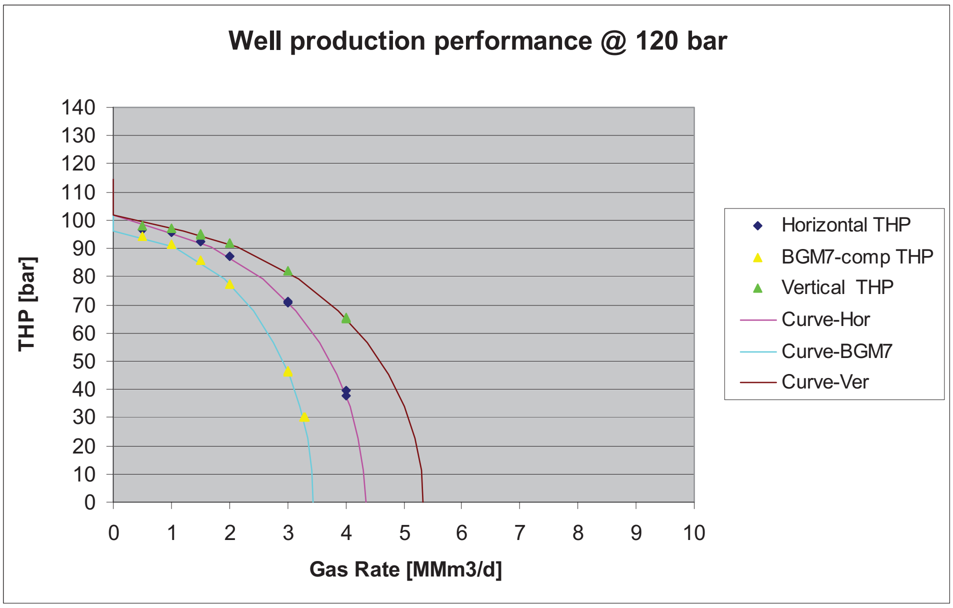

Figure 7-28 Well production performance mid case (BELL_050_H06_H11), 7 5/8” Tbg’s.

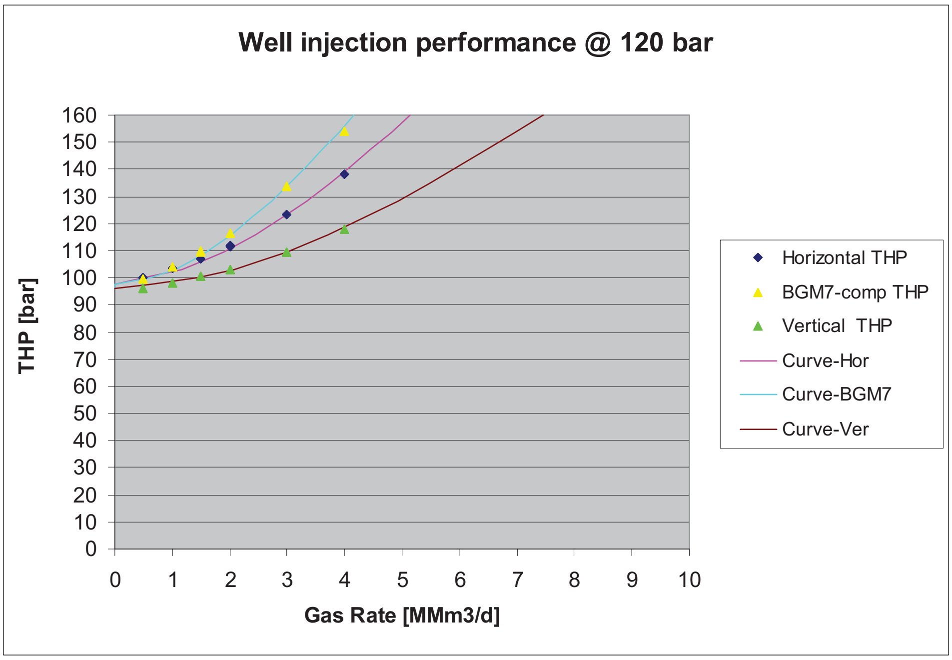

Figure 7-29 Well injection performance mid case (BELL_050_H06_H11), 7 5/8" Tbg's.

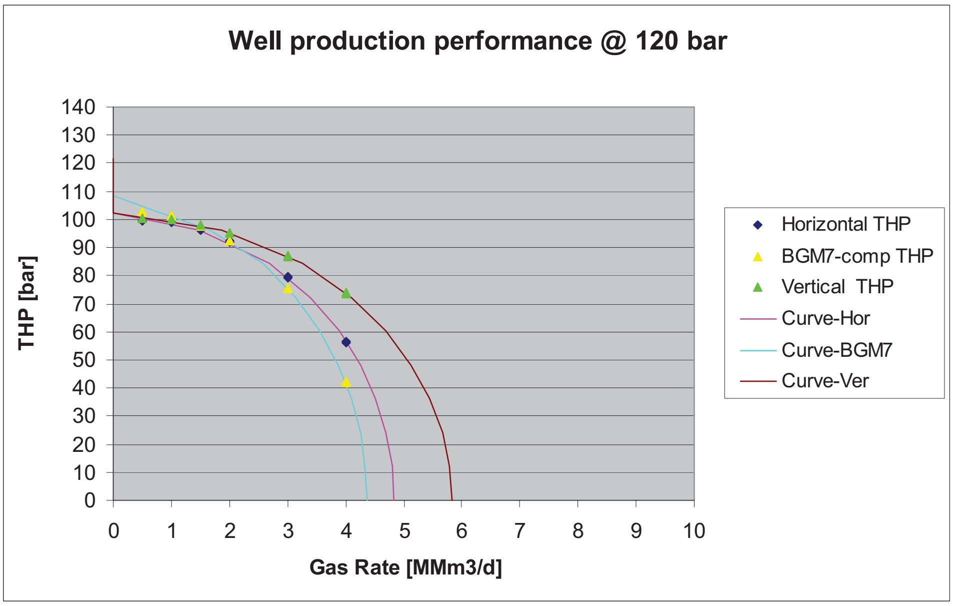

Figure 7-30 Well production performance high pessimistic case (DISMIDHIGHKV_H06_H11), 7 5/8" Tbg's.

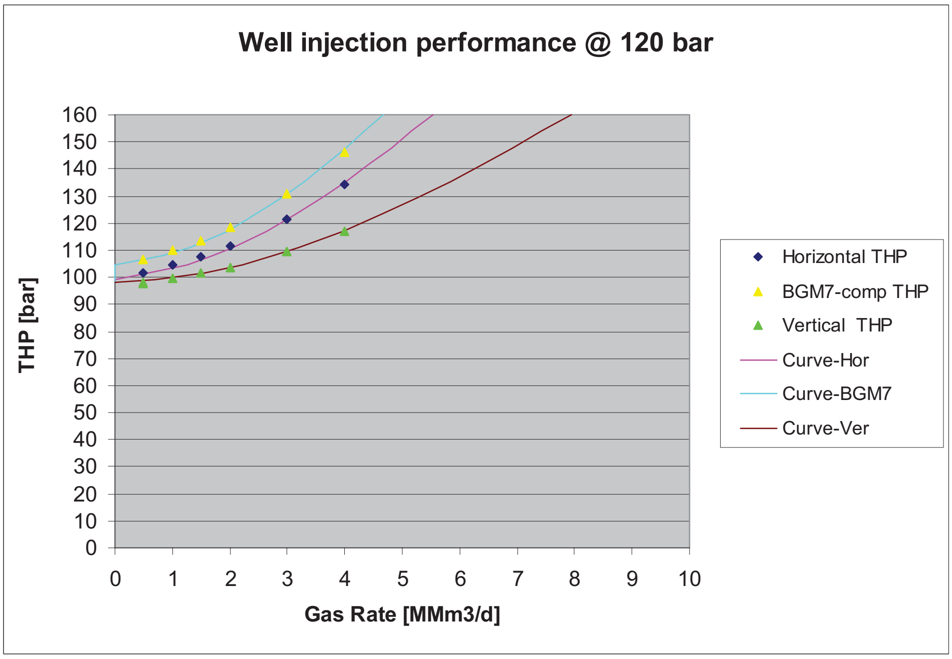

Figure 7-31 Well injection performance high pessimistic case (DISMIDHIGHKV_H06_H11), 7 5/8" Tbg's.

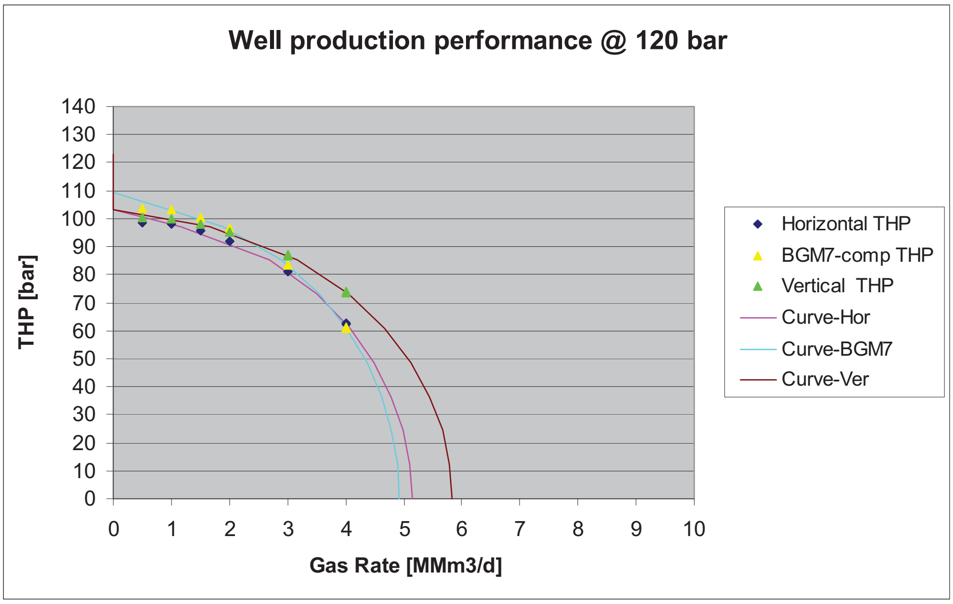

Figure 7-32 Well production performance high optimistic case (DISMIDHIGHKV), 7 5/8" Tbg's.

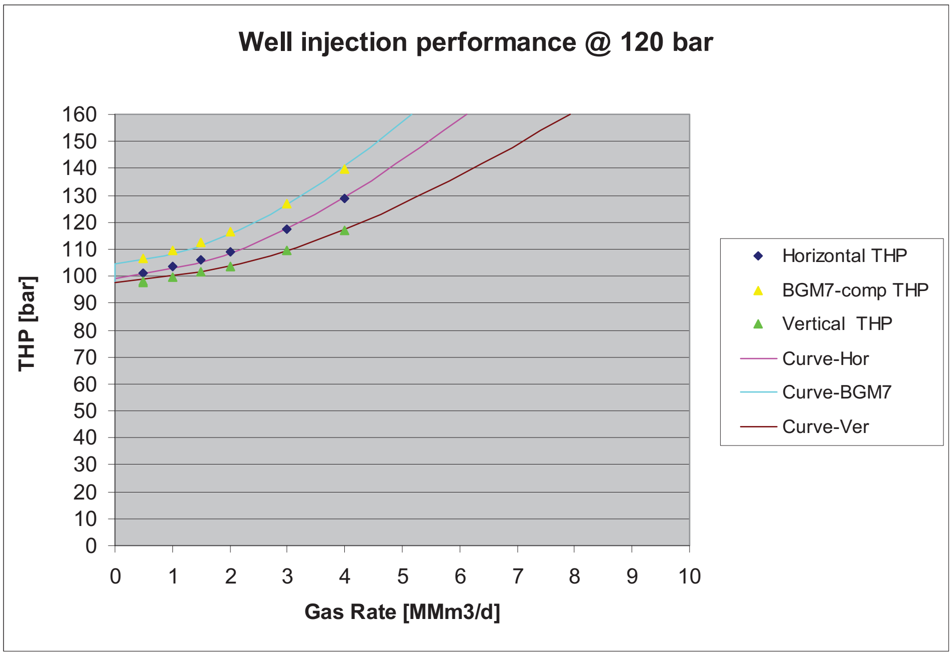

Figure 7-33 Well injection performance high optimistic case (DISMIDHIGHKV), 7 5/8" Tbg's.

7.4 Eclipse runs specification

Input decks Bergermeer UGS for performance curves		
BAG25_ALT2_TESTDES_R01_V007.DATA	Base run Phase1	
BAG25_ALT2_TESTDES_R01_J1.DATA	Cushion gas 8 --> 10 BCM, working gas 3 -->6 bmc	
BAG25_ALT2_TESTDES_R01_J2.DATA	new lift curves all wells vertical	
BAG25_ALT2_TESTDES_R01_J3.DATA	new lift curves, vert + hor	
BAG25_ALT2_TESTDES_R01_J4.DATA	cushion 11 --> 13.7	
BAG25_ALT2_TESTDES_R01_J5.DATA	WDFAC ipv WDFACCOR	
BAG25_ALT2_TESTDES_R01_J6.DATA	new lift cirves	
BAG25_ALT2_TESTDES_R01_J7.DATA	timesteps added 2 MMm3/d for capacity curves	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J7.DATA	for other model capacity curves	
BAG25_ALT2_TESTDES_R01_J8.DATA	timesteps capacity curves changed to max 4 MMm3/d per well and WDFACCOR in original HM-FILE	
BAG25_ALT2_TESTDES_R01_J9.DATA	timesteps capacity curves changed to max 4 MMm3/d per well and WDFACCOR in original HM-FILE	
BAG25_ALT2_TESTDES_R01_J10.DATA	only V1 (MAIN), H5 (MAIN), H1 (CMP-7)	
BAG25_ALT2_TESTDES_R01_J11.DATA	for run N5	
BAG25_ALT2_TESTDES_R01_J12.DATA	2.9 MM m3/d ipv 2 MM m3/d during cycles	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J13.DATA	lowperm, high kv run, different wells	
BAG25_ALT2_TESTDES_R01_J14.DATA	new lift curves for horizontals	
BAG25_ALT2_TESTDES_R01_J15.DATA	skin= 10, new lift curves for horizontals	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J16.DATA	new model, new curves	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J17.DATA	new model, new curves, skin =10, (= sensitivity)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J18.DATA	new model, new curves, compr. =1e-4 [1/bar] (sensitivity)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J19.DATA	15 wells base case, 11 vertical in MAIN, 4 horizontal in CMP-BGM-7	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J20.DATA	15 wells base case, skin 10	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J21.DATA	new model, curves for big bore (8 5/8)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J22.DATA	new model, curves for modified steel roughness (0.0005 --> 0.00015 inch for stainless steel) , = 20 well base cas	
BAG25_ALT2_AQF_TESTDES_R01_J23.DATA	highkh model with (small) aqf, new curves	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J24.DATA	15 wells base case, 11 vertical in MAIN, 4 horizontal in CMP-BGM-7, big bore (8 5/8)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J25.DATA	new model, new curves,shorter horizontals	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J26.DATA	new model, curves for big bore (9 5/8)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J27.DATA	15 wells base case, big bore (9 5/8)	
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J28.DATA	LARGE BASE CASE, 8 5/8", 16 wells	3000m horizontal tubing, vertical roughness 0.0005"
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J29.DATA	XLARGE BASE CASE, 9 5/8", 17 wells	3000m horizontal tubing, vertical roughness 0.0005"
BAG25_ALT2_DISMIDHIGHKV_TESTDES_R01_J30.DATA	XLARGE 7 5/8", 24 wells	3000m horizontal tubing, vertical roughness 0.0005"
BAG25_ALT2_DISMIDHIGHKV_UGS_M758_J31.DATA	MEDIUM BASE CASE, 7 5/8", 15 wells	3600 m horizontal tubing, vertical roughness 0.00015", bfls4 runs
BAG25_ALT2_DISMIDHIGHKV_UGS_L758_J32.DATA	LARGE BASE CASE, 7 5/8", 20 wells	3600 m horizontal tubing, vertical roughness 0.00015", bfls4 runs
BAG25_ALT2_DISMIDHIGHKV_UGS_L858_J33.DATA	LARGE BASE CASE, 8 5/8", 16 wells	3600 m horizontal tubing, vertical roughness 0.00015", bfls4 runs
BAG25_ALT2_DISMIDHIGHKV_UGS_XL758_J34.DATA	XLARGE BASE CASE, 7 5/8", 24 wells	3600 m horizontal tubing, vertical roughness 0.00015", bfls4 runs
BAG25_ALT2_DISMIDHIGHKV_UGS_XL958_J35.DATA	XLARGE BASE CASE, 9 5/8", 17 wells	3600 m horizontal tubing, vertical roughness 0.00015", bfls4 runs
BAG25_ALT2_DISMIDHIGHKV_UGS_J_H06_H11.DATA	LARGE BASE CASE, 7 5/8", 20 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_UGS_H06_H11_L858.DATA	LARGE BASE CASE, 8 5/8", 16 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_UGS_H06_H11_XL958.DATA	XLARGE BASE CASE, 9 5/8", 17 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_100_J_H06_H11.DATA	BELL 100 profile over PERM, 7 5/8", 20 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_050_J_H06_H11.DATA	BELL 050 profile over PERM, 7 5/8", 20 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_J_H06_H11.DATA	BELL 050 ALT profile over PERM, 7 5/8", 20 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_UGS_L858.DATA	BELL 050 aLT profile over PERM, 8 5/8", 16 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_UGS_XL958.DATA	BELL 050 ALT profile over PERM, 9 5/8", 17 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_J_H06_H11_LOW.DATA	BELL 033 ALT profile over PERM, 7 5/8", 20 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_J_H06_H11_LOWINT.DATA	BELL 033 ALT profile over PERM, 7 5/8", 20 wells, ALL WELLS FOR Perf.Curves, to see well-interference	
BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_UGS_L858.DATA	BELL 033 ALT profile over PERM, 8 5/8", 16 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	
BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_UGS_XL958.DATA	BELL 033 ALT profile over PERM, 9 5/8", 17 wells, V01, H06 and H11 for Perf Curves ipv V01, H05, H01	

Table 7-2 Input decks Bergermeer UGS for Performance curves

Input decks Bergermeer UGS without performance curves	
BAG25_ALT2_TESTDES_R01_J7.DATA	Base Case
BAG25_ALT2_TESTDES_R01_N1.DATA	3 horizontal wells added in compartment-7
BAG25_ALT2_TESTDES_R01_N2.DATA	comp BGM-7 8 weeks more injection at 2 MM m3 per well--> cushion 8-->9.15+0.36 = 9.5 bcm
BAG25_ALT2_TESTDES_R01_N3.DATA	WDFACCOR 2e-6 ipv 2e-8 --> no change
BAG25_ALT2_TESTDES_R01_N4.DATA	THPmin30 bar BHPmin 60 bar (prod) and BHPmax 150 bar (injection)--> no effect
BAG25_ALT2_TESTDES_R01_N5.DATA	24-->20wells (1 from CMP-7, 3 from MAIN), Qrate 2MM --> 2.4 MMm3/d
BAG25_ALT2_TESTDES_R01_N6.DATA	24-->21wells (3 from MAIN), Qrate 2.4MM --> 2.9 MMm3/d, new curves
BAG25_ALT2_TESTDES_R01_N7.DATA	20wells, Qrate 2.9MMm3/d, leaking FLT to Groet, THPRES 30 bar, MULTFLT *100 (0.02)
BAG25_ALT2_TESTDES_R01_N8.DATA	24-->20wells (1 from CMP-7, 3 from MAIN), Qrate 2.4MM --> 2.9 MMm3/d, new curves
BAG25_ALT2_TESTDES_R01_N9.DATA	20wells, Qrate 2.9MMm3/d, WELLS 2210 m
BAG25_ALT2_TESTDES_R01_N10.DATA	20wells, Qrate 2.9MMm3/d, WELLS 2180 m
BAG25_ALT2_TESTDES_R01_N11.DATA	SKIN = 10, 20wells, Qrate 2.9MMm3/d, WELLS 2180 m
BAG25_ALT2_TESTDES_R01_N12.DATA	DISMIDHIGHKV, 20wells, Qrate 3.1 MMm3/d, WELLS 2180 m, 5 wells in CMP-BGM-7
BAG25_ALT2_TESTDES_R01_N13.DATA	DISMIDHIGHKV, 20wells, Qrate 3.2 MMm3/d, WELLS 2180 m, 5 wells in CMP-BGM-7
BAG25_ALT2_TESTDES_R01_N14.DATA	DISMIDHIGHKV, 20wells, Qrate 3.2 MMm3/d, WELLS 2180 m, 5 wells in CMP-BGM-7 with BGM-12 3.6 rest 3.1 production
BAG25_ALT2_TESTDES_R01_N15.DATA	DISMIDHIGHKV, 15wells, Qrate 3.2 MMm3/d, WELLS 2180 m, 4 wells in CMP-BGM-7
BAG25_ALT2_TESTDES_R01_N16.DATA	DISMIDHIGHKV, 17wells, Qrate 3.2/5.3 MMm3/d, WELLS 2180 m, 6 wells in CMP-BGM-7
BAG25_ALT2_TESTDES_R01_N17.DATA	DISMIDHIGHKV, 16wells, Qrate 3.2/4.4 MMm3/d, WELLS 2180 m, 5 wells in CMP-BGM-7
BAG25_ALT2_TESTDES_R01_N18.DATA	DISMIDHIGHKV, 24wells, Qrate 3.0/3.0 MMm3/d, WELLS 2180 m, wells in CMP-BGM-7
BAG25_ALT2_DISMIDHIGHKV_UGS_M758_N31.DATA	MEDIUM BASE CASE, 7 5/8", 15 wells
BAG25_ALT2_DISMIDHIGHKV_UGS_L758_N32.DATA	LARGE BASE CASE, 7 5/8", 20 wells
BAG25_ALT2_DISMIDHIGHKV_UGS_L858_N33.DATA	LARGE BASE CASE, 8 5/8", 16 wells
BAG25_ALT2_DISMIDHIGHKV_UGS_XL758_N34.DATA	XLARGE BASE CASE, 7 5/8", 24 wells
BAG25_ALT2_DISMIDHIGHKV_UGS_XL958_N35.DATA	XLARGE BASE CASE, 9 5/8", 17 wells
BAG25_ALT2_DISMIDHIGHKV_UGS_L758_N32_GROET.DATA	LARGE BASE CASE, 7 5/8", 20 wells, MULTFLT to GROET (FAULTATS) 0.0002--> 0.02
BAG25_ALT2_DISMIDHIGHKV_UGS_L758_N32_BEL.DATA	LARGE BASE CASE, 7 5/8", 20 wells, MULTX 0.5 - 2 over permeability to reduce permeability CMP-7
BAG25_ALT2_DISMIDHIGHKV_UGS_N_H06_H11.DATA	LARGE BASE CASE, 7 5/8", 20 wells
BAG25_ALT2_DISMIDHIGHKV_BELL_100_N_H06_H11.DATA	BELL 100 profile over PERM, 7 5/8", 20 wells
BAG25_ALT2_DISMIDHIGHKV_BELL_050_N_H06_H11.DATA	BELL 050 profile over PERM, 7 5/8", 20 wells
BAG25_ALT2_DISMIDHIGHKV_BELL_050_ALT_N_H06_H11.DATA	BELL 050 ALT profile over PERM, 7 5/8", 20 wells
BAG25_ALT2_DISMIDHIGHKV_BELL_033_ALT_N_H06_H11_LOW.DATA	BELL 033 ALT profile over PERM, 7 5/8", 20 wells

Table 7-3 Input decks Bergermeer UGS without Performance curves

HM runs for baffles in MAIN block, seen in summer injection test									
BASED ON RUN: BAG25_ALT2_DISMIDHIGHKV_ECLIPSE100_WDF_BFLS									
BFLS	BAFFLESNO north of BGM-6A, MULTFLT 0.1. BAFFLESO south of BGM-6A, MULTFLT 0.1								
BFLS2	MULTFLT 0.01 / 0.01								
BFLS3	BAFFLESO y=153-->y=158, MULFLT 0.1 / 0.1								
BFLS4	**BAFFLESO y=153-->y=158, 0.01 / 0.1**					**BASE CASE**			
BFLS5	0.01 / 0.05								
BFLS6	0.05 / 0.1								
BFLS7	ONLY BAFFLENO (0.01)								
BFLS8	ONLY BAFFLESO (0.1)								
BFLS9	0.002 / 0.1								

Table 7-4 Input decks Bergermeer UGS for faults seen in Summer Injection Test

STARTUP0	1st year: 3 wells MAIN, 2 wells CMP-7		
STARTUP	1st year: 4 wells MAIN, 1 well CMP-7	Rate 3.2 MM m3/d/well	
STARTUP1	1st year: 4 wells MAIN, 1 well CMP-7	Rate 3.2 MM m3/d/well	
STARTUP2	1st year: 4 wells MAIN, 1 well CMP-7	Rate 3.0 / 3.5 MM m3/d/well	End of Fieldlife 64 MM
STARTUP3	1st year: 4 wells MAIN, 1 well CMP-7	Rate 3.0 / 3.5 MM m3/d/well	EOF 50 MM m3/d
STARTUP4	BHP MAX 144 bar in year4 ipv 150	Rate 3.0 / 3.5 MM m3/d/well	EOF 50 MM m3/d
STARTUP5	**BHP MAX 60/62/105/145 bar year 1,2,3,4**	Rate 3.0 / 3.5 MM m3/d/well	EOF 50 MM m3/d

Table 7-5 Input decks Bergermeer UGS drilling sequence and end-of-fieldlife

V008_COMPDAT_UGS.INC	diameter 0.1778m, 24 wells
BGM_UGS_2180_V009.INC	diameter 0.1778m, SKIN10
BGM_UGS_2180_V010.INC	diameter 0.1778m, 20 wells, 4HOR, 5 CMP7, 11 VERT
BGM_UGS_2180_V11.INC	diameter 0.1778m, 15 wells, 0 HOR, 4 CMP-7, 11 VERT
BGM_UGS_2180_V12.INC	diameter 0.1905m (7 5/8"), +connection factors
BGM_UGS_2180_V13.INC	diameter 0.2159m, 8 5/8"
BGM_UGS_2180_V14.INC	diameter 0.2413m, 9 5/8"
BGM_UGS_2180_V15.INC	diameter 0.1778m, 11 VERT, 6 CMP7
BGM_UGS_2180_V16.INC	diameter 0.2159m, 8 5/8", 6 CMP7
BGM_UGS_2180_V17.INC	diameter 0.2413m, 9 5/8", 6 CMP7
BGM_UGS_2180_V18.INC	diameter 0.1778m, 7 HOR, 11 VERT, 6 CMP7

Table 7-6 Well completion data include decks

V001_TEST_CYCLE_N8.INC	cycles 3.2 MM m3/d all wells
V001_TEST_CYCLE_N9.INC	cycles 3.2 MM m3/d all wells
V001_TEST_CYCLE_N12.INC	cycles 3.0 MM m3/d all wells
V001_TEST_CYCLE_S0.INC	PI-run only, V01 for MAIN, H01 for BGM-7
V001_TEST_CYCLE_V01_H11.INC	H11 for BGM-7, cycles 3.2 MM m3/d per well
V001_TEST_CYCLE_V01_H06_H11.INC	H06 for MAIN, H11 for BGM-7, cycles 3.2 MM m3/d per well
V001_TEST_CYCLE_V01_H06_H11_INT.INC	ALL WELLS, cycles 3.2 MM m3/d per well
V001_TEST_CYCLE_V01_H06_H11_XLARGE.INC	H06 for MAIN, H11 for BGM-7, cycles 3.0 MM m3/d per well
V001_TEST_CYCLE_R01_N8.INC	H05 for MAIN, H01 for BGM-7, cycles 3.2 MM m3/d wells MAIN, 3.2 MM m3/d HOR WELLS
V001_TEST_CYCLE_R01_N9.INC	H01 for BGM-7, cycles 3.2 MM m3/d wells MAIN, 3.2 MM m3/d HOR WELLS
V001_TEST_CYCLE_R01_N10.INC	H11 for BGM-7, cycles 4.36 MM m3/d wells MAIN, 3.2 MM m3/d HOR WELLS
V001_TEST_CYCLE_R01_N11.INC	H11 for BGM-7, cycles 4.91 MM m3/d wells MAIN, 3 MM m3/d HOR WELLS

Table 7-7 Includes for production / injection rates of UGS cycles and performance curves