The Analysis of Dynamic Data in Shale Gas Reservoirs – Part 3

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In Part 1 of this series of WEB publications we described the different analysis techniques currently available for the study of fractured horizontal wells in the context of shale gas.

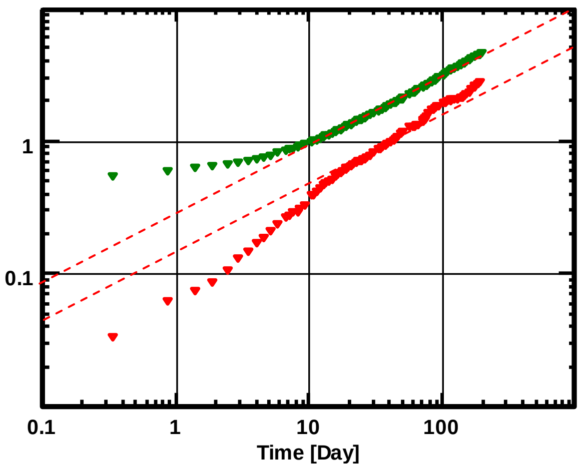
In Part 2 we defined a workflow and applied it to a real case study, based on the first eight months of production of a fractured horizontal well. There was no problem in matching the data with any of the proposed techniques, but the forecast derived from each proved to be different.

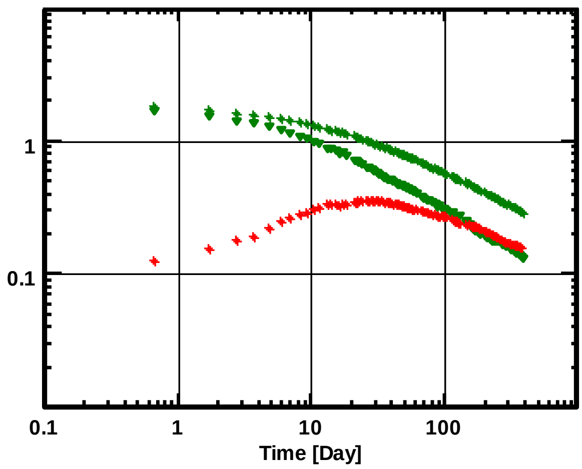
Our position at the end of Part 2 was that the forecast based on the linear flow straight lines and single equivalent fracture would be over optimistic, the forecast based on an analytical model would be pessimistic, whilst only the numerical model, reproducing the geometry, the nonlinearity of this very low permeability diffusion and, to a lesser degree, desorption, would provide a realistic forecast.

Late in April we received an additional ten months of data. In this third paper, we are checking the validity of our modeling. The short answer is that the forecasts deviated as expected, which is pretty comforting even though it is not, in any way, proof positive.

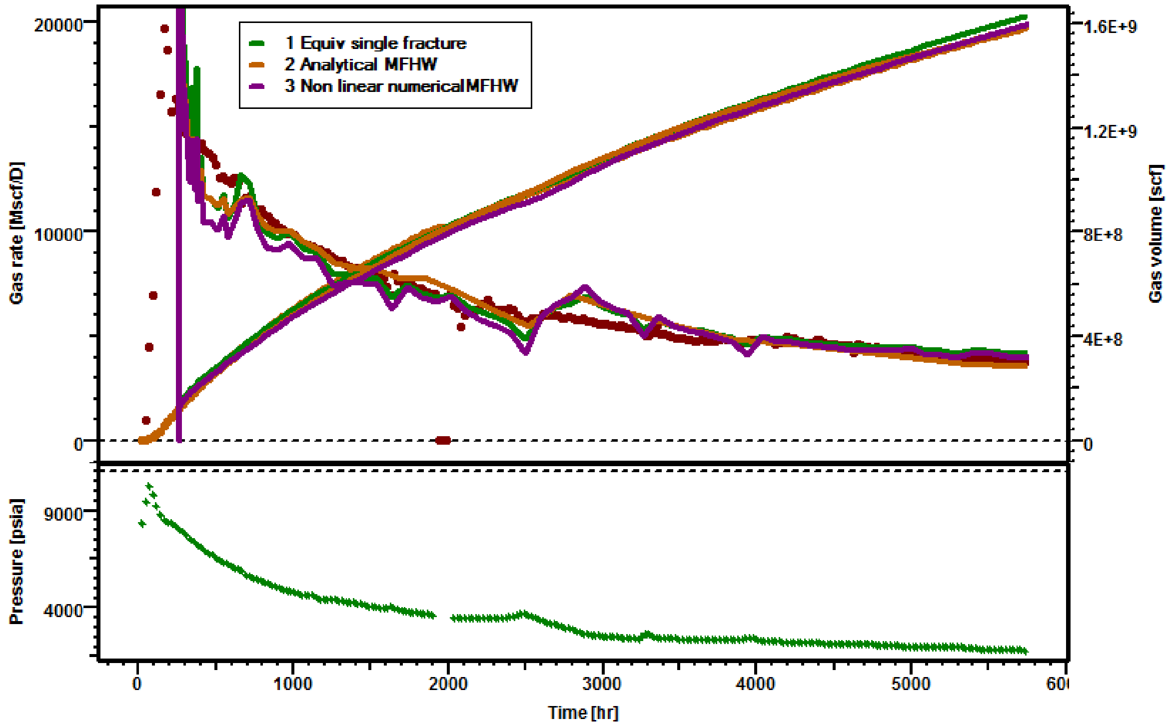
1 - Summary of the previous case study

A pre-requisite to understanding this paper is to have read Part 2 and preferably Part 1. Therefore, we will not repeat the details of the input and output parameters of this case.
The short story is that the behavior of the first eight months of data, shown below on a loglog and a Blasingame plot, is still, in the main, dominated by linear flow.



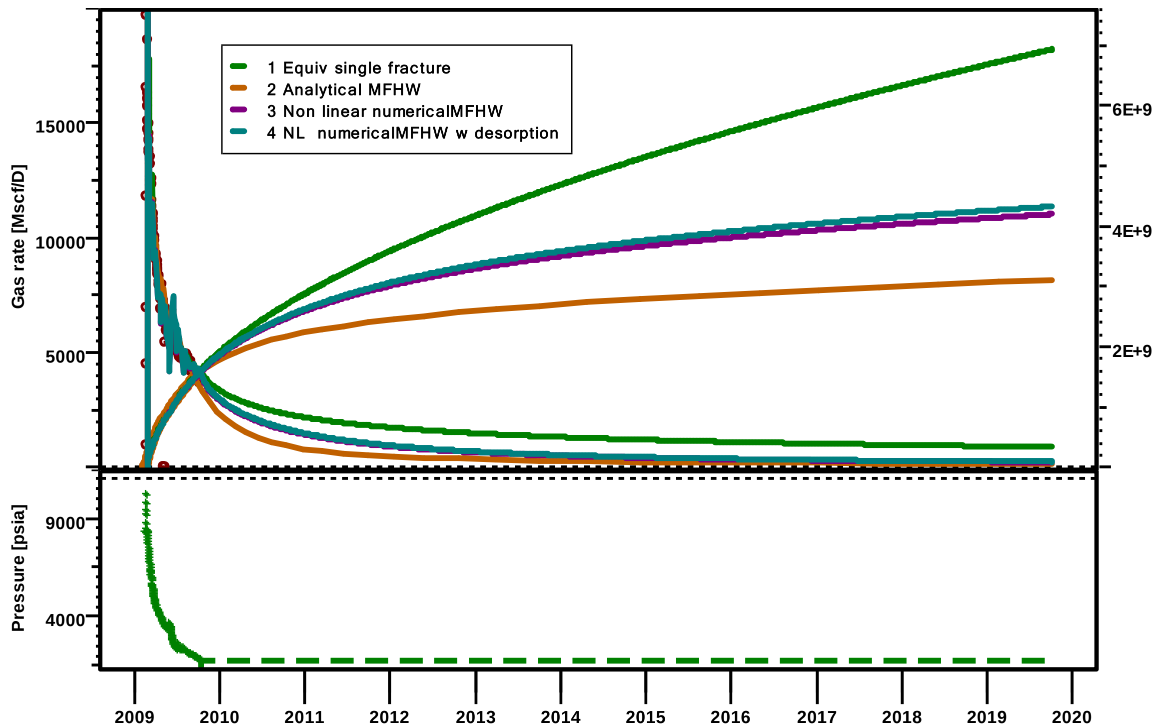


The data were analyzed and matched using (1) a square root plot defining a single equivalent fracture, (2) an analytical model for fractured horizontal well and (3) our numerical fractured horizontal well model using nonlinear (NL) diffusion. The history plot below shows that all models matched the production very well. It was however noticed that both analytical and numerical models indicated that we were reaching the end of pure linear flow, and interference between fractures was beginning to show (log-log plot).



History match comparison

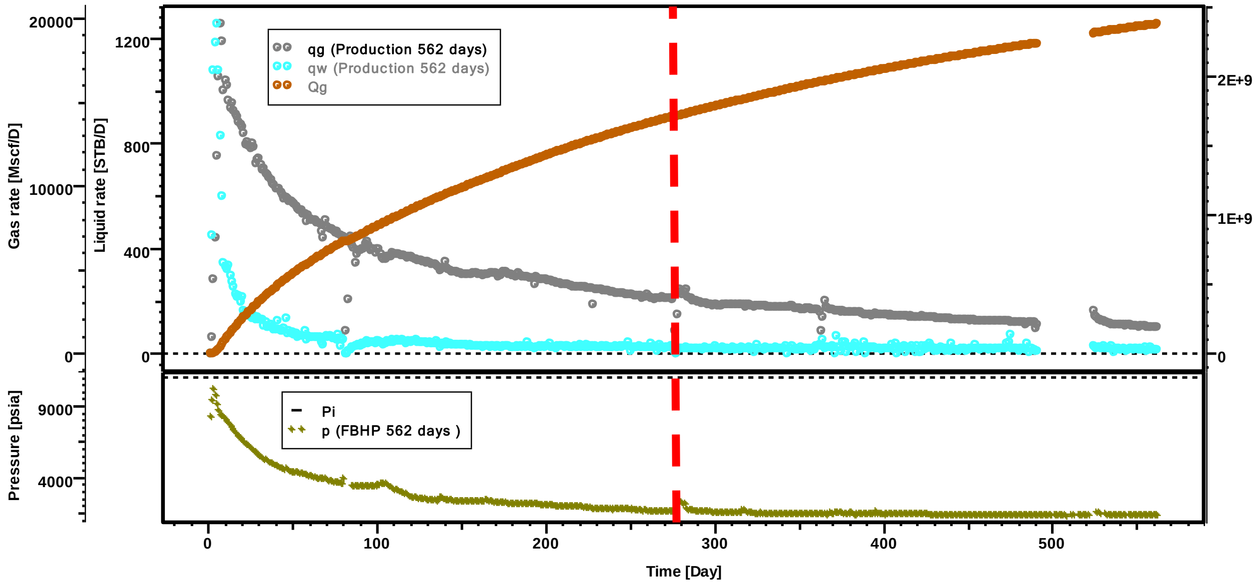
Consequently, when we started to forecast the next ten years of production, assuming the same given flowing pressures, the three models began diverging noticeably. Only the two numerical models, with or without desorption, gave comparable results.

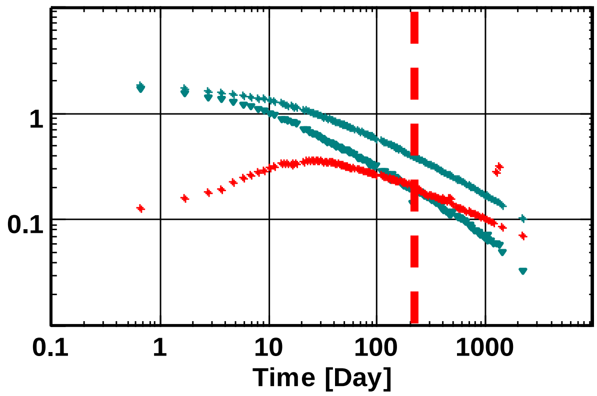


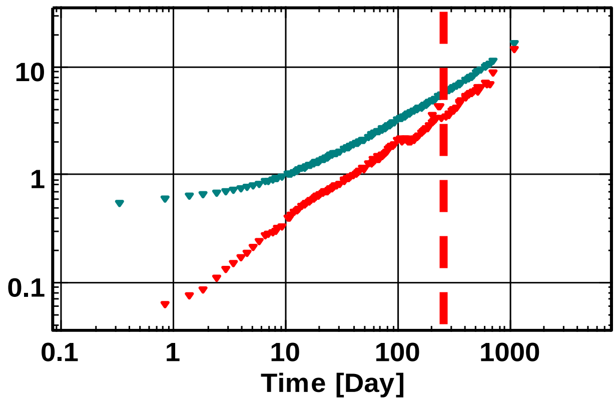
Comparison of 10-year forecasts

2 - Model QC with additional production data

We now have a further ten months of data from the same well that is shown after the dashed red line in the following plots. The resulting eighteen months of production and pressures are shown in the history, Blasingame and loglog plots below.





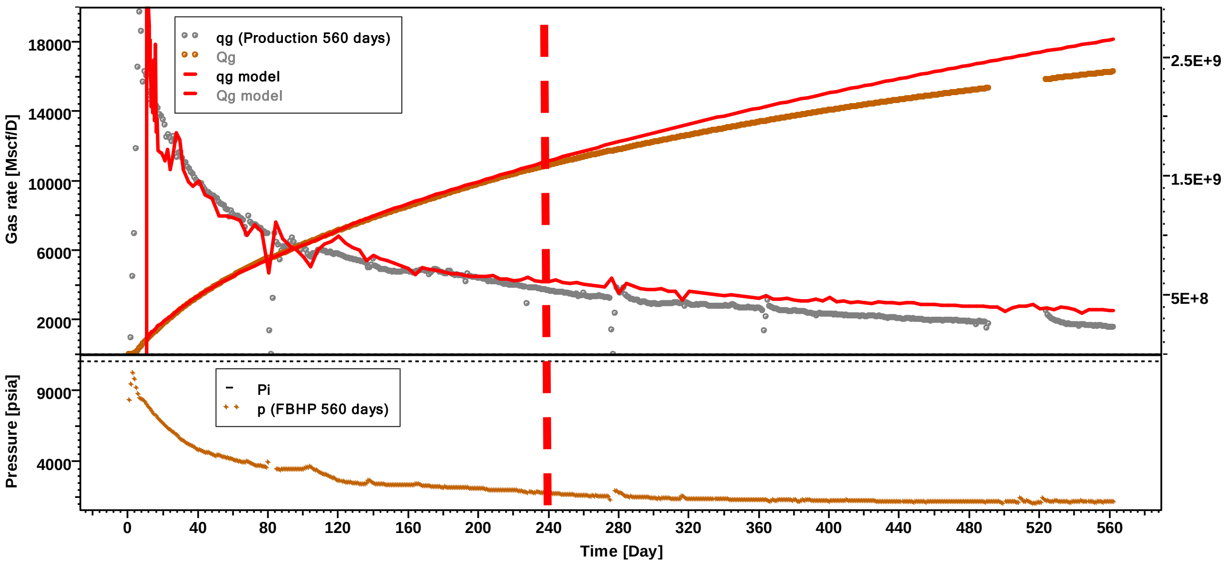


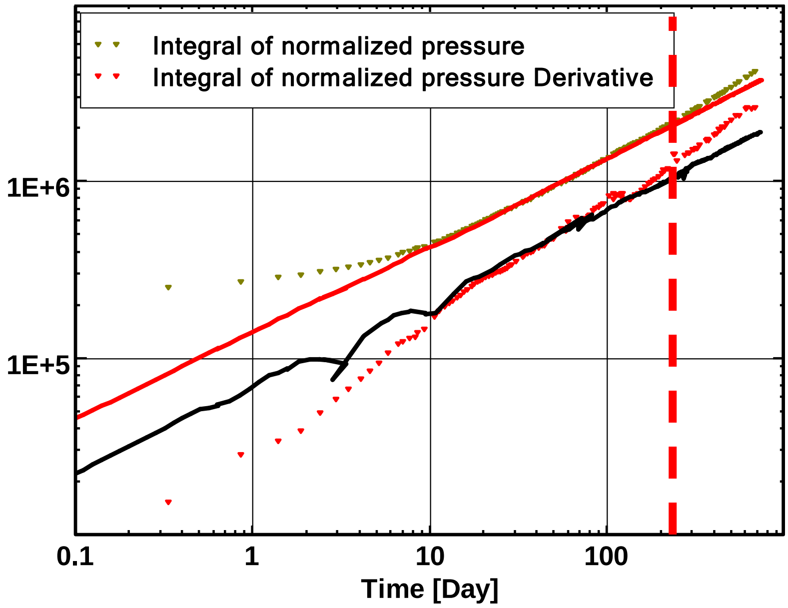
History plot, log-log plot and Blasingame plot with the additional production data

It is time for us to check the conclusions of Part 2. We will re-run each of the previous models. Instead of using an assumed flowing pressure we are going to use the actual recorded pressure. Besides this the model parameters remain unchanged.

2.1 - Straight line linear flow model

With the parameters defined by matching the first 240 days of data, and using the complete pressure history, we now simulate the single equivalent fracture model defined with the straight line method to the, now, 18 months of production history.



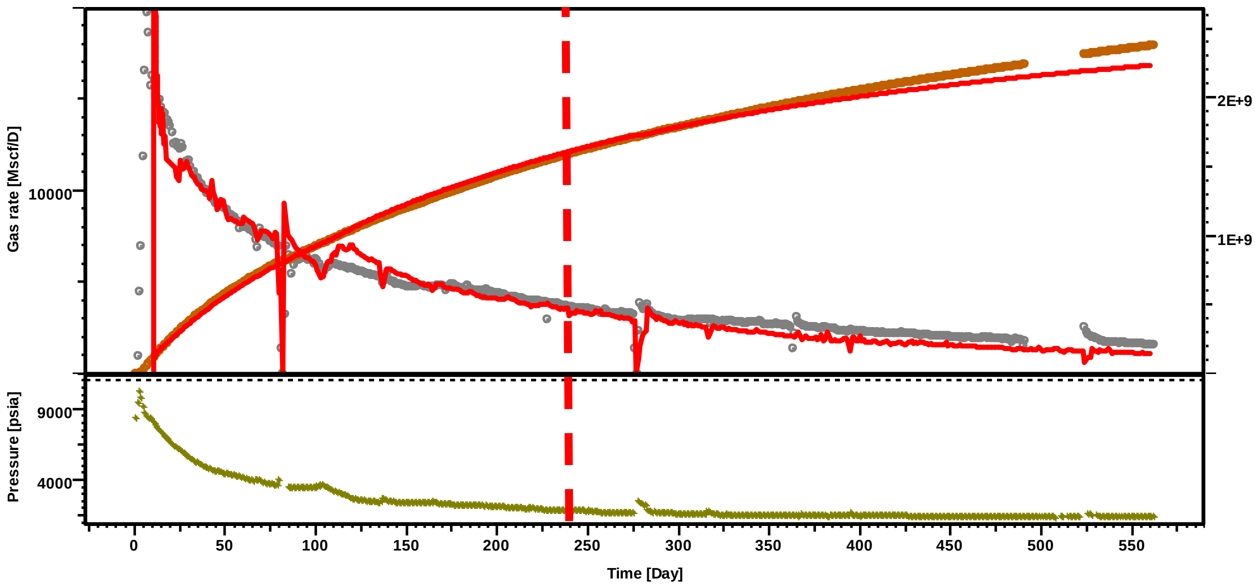


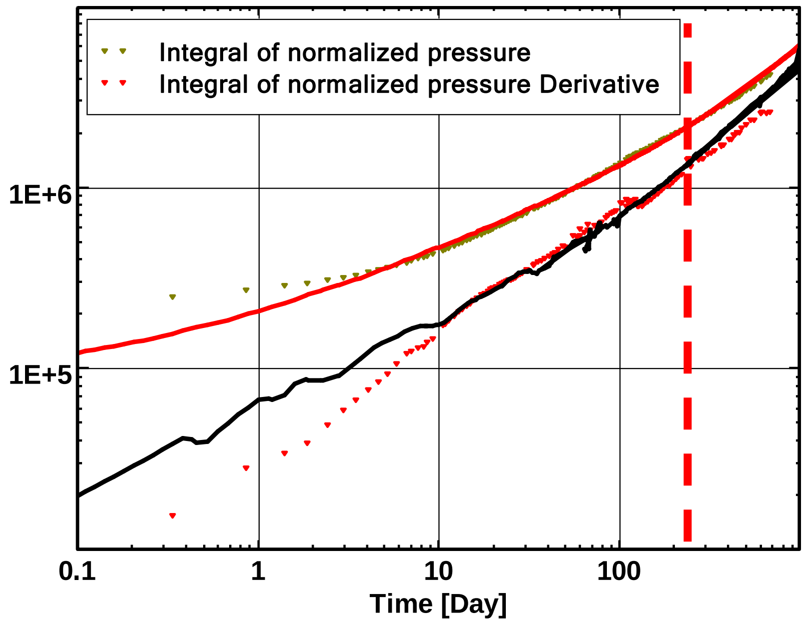
History match & log-log match of the equivalent single fracture model

The simulation deviates strongly from the new data after 240 days, upwards on the history plot and downwards on the loglog plot. The single equivalent fracture is much too optimistic. This is explained by the fact that the single equivalent fracture model does not account for the interference between the real fractures. This is in line with the conclusions and forecasts of Parts 1 and 2.

2.2 - Analytical fractured horizontal well model

With the parameters obtained in Part 2 by matching the first 240 days of data, and using the complete pressure history we now simulate the analytical fractured horizontal well model for the 18 months of total production history.



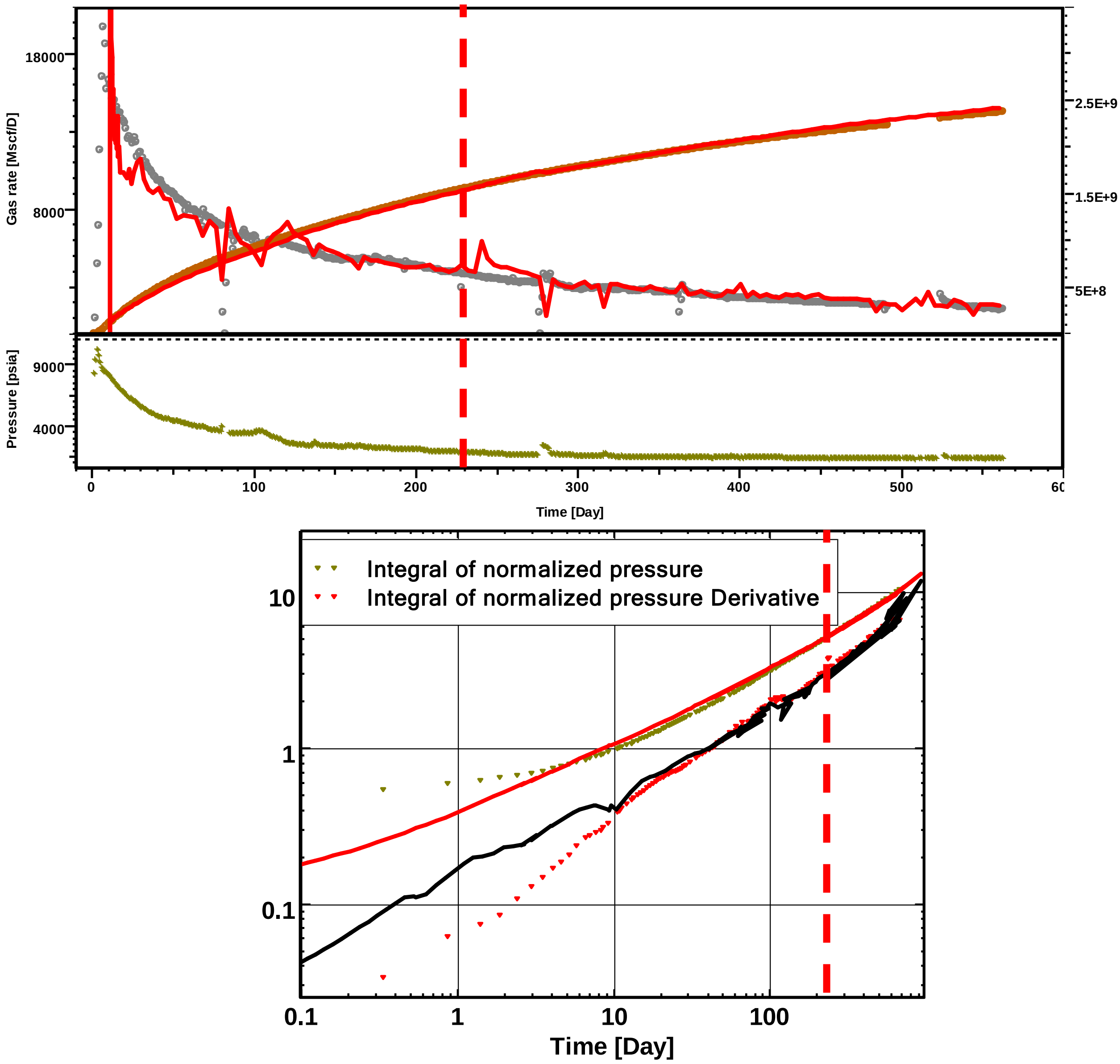


History match & log-log match of the analytical MFHW model

The simulation deviates slightly from the new data after 240 days, downwards on the history plot and upwards on the loglog plot. The analytical model is too pessimistic. This is explained by the fact that the analytical model takes into account the 'bad news' due to fracture interference, but not the 'good news' due to the nonlinearity of the problem. What is missing is the intense pressure gradients due to the extremely low permeability creating zones where the gas compressibility is much higher than the one uniformly used in the analytical model. This is in line with the conclusions and forecasts of Parts 1 and 2.

2.3 - Non linear numerical MFHW model

With the parameters obtained in Part 2 by matching the first 240 days of data, and using the complete pressure history we now simulate the numerical fractured horizontal well model for the 18 months of total production history.



History match & log-log match of the non-linear numerical MFHW model

The nonlinear numerical model consistently matches the data, and the deviation from the linear flow regime, less pronounced than on the analytical model, is in line with that observed on the new production data.

Naturally we could further fine-tune the model to obtain a better match as we receive new data. But the important point is that the model trend follows consistently the data trend. Both the interference due to geometry and the non-linear treatment of the gas PVT have been captured precisely by the model, and thus the well productivity is assessed correctly.

3 - Conclusion

This is not the silver bullet. Other elements or operational changes could have impacted the system and made the numerical model inconsistent with the data without questioning the technical considerations and the workflow presented in Part 1 and applied in Part 2. These changes could have even made the straight-line method or the analytical model look embarrassingly better. So we still have to keep a low profile.

However it is very encouraging to see that, in the absence of any change of the system, the reservoir/well proxy that is the numerical model, however simplified, seems to match consistently the production of the real system.

We therefore stick today to our original point: although they can be useful and are indeed recommended in the workflow to build the model, straight line methods/single equivalent fractures and analytical fractured horizontal wells should NOT be used to forecast the long term system production, and the numerical model is, so far, the best (or least bad!) way to perform such a forecast.