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Integrating Pressure Transient Analysis into History Matching

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Summary

Broad availability of continuous pressure measurements from Permanent Downhole Gauges (PDGs) has revived interest in using Pressure Transient Analysis (PTA) to improve history matching of reservoir models. Reproducing pressure transient responses in reservoir simulations as a way of conditioning parameters and realizations of geological models, also known as geological well testing, is a rapidly growing R&D area with many applications recently reported.

The main focus of this paper is integration of PTA into reservoir simulation. We present a workflow which combines time-lapse PTA, employing analytical, single-phase models, with smooth transition to numerical, multi-phase simulations. Application of this workflow is illustrated by a case study with horizontal well injection into a segment of a fractured carbonate reservoir. The value of using pressure derivative in history matching is demonstrated through the evaluation of a hypothesis of well connection to conductive faults. The analysis of pressure transients in combination with numerical simulations finally argued for absence of such connection for the analysed history period.

Introduction

Pressure Transient Analysis (PTA) as a tool for evaluating well-reservoir parameters from pressure and rate measurements (Bourdet, 2002) has now many new applications due to installation of Permanent Downhole Gauges (PDGs, Horne, 2007). Time-lapse PTA of PDG data is one of such applications, utilized to monitor changes in well-reservoir parameters (Shchipanov et al., 2014). History of these changes is essential for updating and history matching of large scale reservoir models. Using well test data for conditioning geological models, also known as geological well testing, is a rapidly growing area of applications, with particular focus on fractured and fluvial reservoirs (Hamdi et al. 2014, Aljuboori et al., 2015, Egya et al., 2016).

Pressure derivative analysed in PTA can become an additional history matching parameter. Including pressure derivative into history matching provides new information about flow patterns in the reservoir and direct possibility to separate well and reservoir effects, which is crucial for reservoir performance forecast. In this paper, a workflow focused on integrating PDG data in a combination with PTA (Shchipanov et al., 2014) into reservoir simulation is illustrated by an example of water injection into a segment of carbonate fractured reservoir.

Integrating PDG data and PTA into history matching

Interpretation of pressure transient data from well tests or PDGs is usually carried out with fast (analytical) single-phase models, resulting in well-reservoir parameters providing that pressure transient(s) can be matched. History matching of large-scale, multi-phase (numerical) reservoir models mainly focuses on less frequent rate and pressure measurements, chiefly due to long history and large data sets to be addressed. Still history matching of observations with a model is the main objective in both cases. Availability of frequent, high quality pressure measurements from PDGs in combination with improved functionality and performance of reservoir simulators, make integration of pressure transients and derivatives into history matching attractive. This can improve the predictability of reservoir models by catching main flow patterns and correct separation of well and reservoir effects.

The workflow

A workflow for integrating PDG data and PTA into history matching is illustrated with a segment reservoir simulations including:

- Time-lapse PTA to interpret PDG data with analytical models, disclosing eventual historical variations in well-reservoir parameters.
- Integrate both PDG data (including pressure transients) and the history of well-reservoir parameters into a 2D segment reservoir model.
- History match of the segment model paying special attention to pressure transients and derivatives.

A case study

Application of this workflow is illustrated with an example of cold water injection into a previously depleted reservoir segment (Figure 1). The attention is on the long horizontal injector located towards the

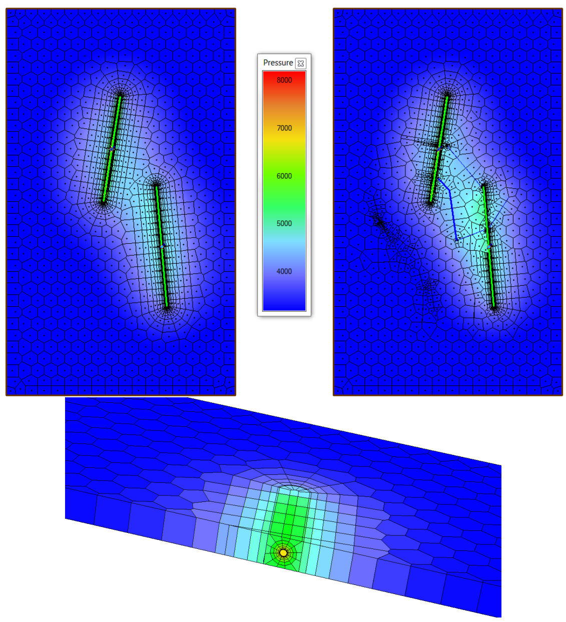

Figure 1 *2D segment model without (left) and with inter-well conductive faults (right): pressure distribution at the end of history simulations. 3D grid near well (bottom).*

North-Western part of the segment. A nearby (South-East) injector was also included in the model, while no-flow conditions were applied at the external boundaries. Based on evaluations from preliminary runs, these two remedies should provide reasonable boundary conditions for the well in focus.

The well injection history consists of sequential flowing and shut-in periods (Figure 2). Plots of the shut-in pressure derivatives in log-log scale (Figure 3) shows an upward shifting trend, indicating declining flow capacity with time.

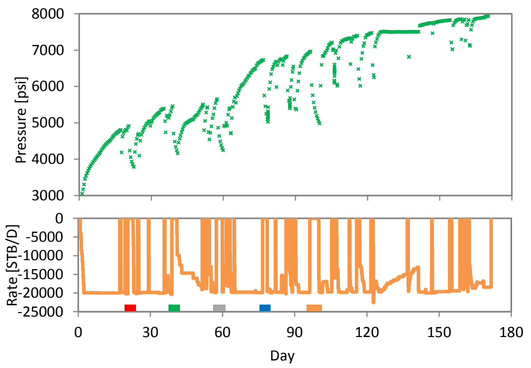

Figure 2 *The well history: sequential injection and shut-in (pressure fall-off) responses.*

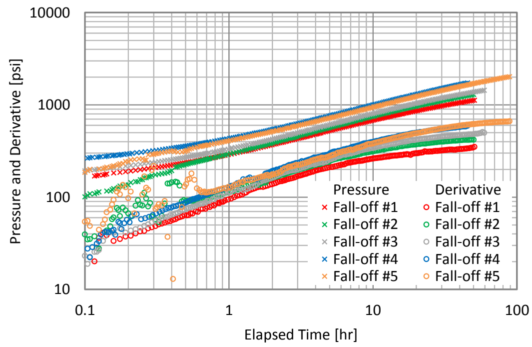

Figure 3 *Time-lapse PTA: the sequential fall-off responses (Figure 2) in log-log scale.*

The time-lapse PTA was carried out by means of an analytical, single-phase model of a horizontal wellbore, using negative skin to represent well stimulation (multiple induced fractures). Modelling parameters, namely reservoir conductivity, *kh,* and skin-factor, were tuned to match each pressure fall-off, step-by-step (Figure 4), keeping the fluid viscosity (μ) constant. This tuning provided local history match to individual shut-ins and related history periods, while unsurprisingly showing some mismatch of other shut-ins / periods (Figure 5).

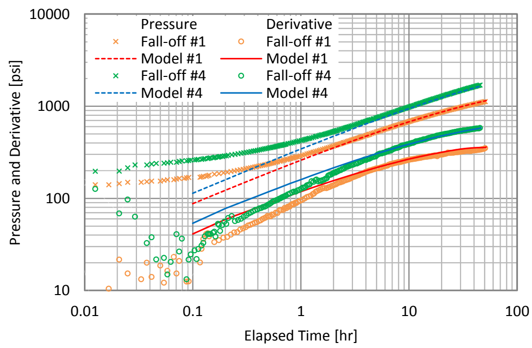

Figure 4 *Tuning analytical model parameters to match two fall-off responses from the sequence (Figure 3).*

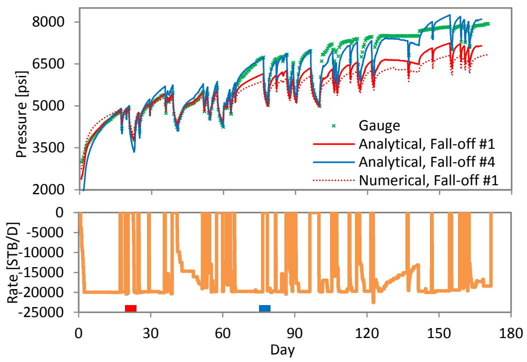

Figure 5 *Two alternative history matching scenarios with the analytical model tuned to fall-offs 1 and 4. The numerical model employed the analytical model parameters tuned to fall-off 1 (Figure 4).*

Summarizing the results of all shut-in interpretations (Figure 6), a declining trend in *kh* (actually, mobility, *kh/*μ) was found, while skin did not vary significantly. Reservoir cooling due to cold water injection, leading to increasing fluid viscosity, μ*,* may be a reason for the observed decline in fluid mobility *(kh/*μ). Matching of the whole history was difficult using analytical model and fixed parameters (which are, in fact, changing over time). Multi-phase numerical simulation was used as next step, allowing more flexibility in covering observed changes in parameters.

It should be noted that a transition from single-phase to two-phase mobility is needed when applying analytical PTA results in reservoir simulation. As an approximation, the following relationship was suggested and used in this study:

$$\left[\frac{kh}{\mu}\right]_{Single-phase} \leftrightarrow \left[\frac{kh}{2}\left(\frac{k_{rw}^{max}}{\mu_w}+\frac{k_{ro}^{max}}{\mu_o}\right)\right]_{Two-phase},$$

where k_{rw}^{max} and k_{ro}^{max} – are maximum relative permeabilities for water and oil, μ_w and μ_o – water and oil viscosities. Also, a correct modelling of the flow regimes nearby a horizontal wellbore requires local 3D grid around the wellbore (Figure 1, which may be handled manually or automatically in different reservoir simulators). This is essential, for example, for simulating the local radial flow towards the well as reflected in the pressure derivative stabilization observed in Figure 4.

As a first guess, the *kh/μ* result from the interpretation of the first fall-off was applied in the 2D numerical simulation (Figure 1). The history match was similar, though not identical to that of the analytical model (Figure 5), primarily due to the introduction of a more compressible fluid, oil, into the fluid system in combination with the mobility approximation defined above.

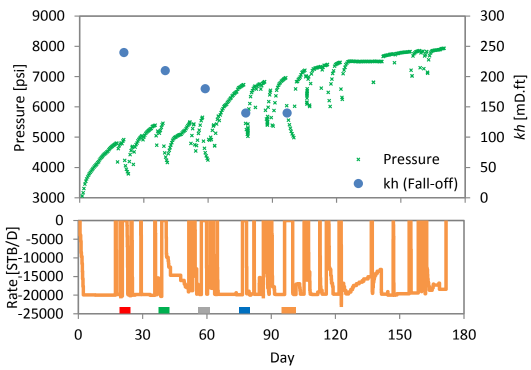

Figure 6 *Results of time-lapse PTA: historical changes of reservoir conductivity (kh).*

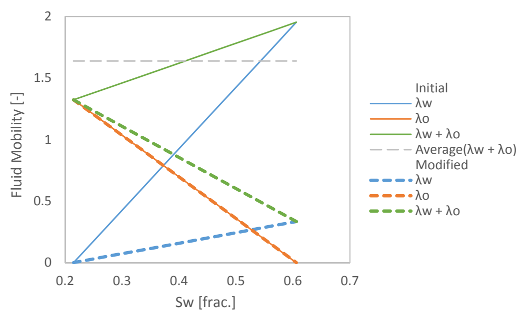

Figure 7 *Water (λ_w), oil (λ_o) and total ($\lambda_w+\lambda_o$) mobilities ($\lambda=kh/\mu$): initial (left) and modified (right) to account for the mobility decline (Figure 6).*

In the numerical simulations, the observed decline in fluid mobility (Figure 6) was approximated by modifying relative permeability and, therefore, fluid mobility curves (Figure 7), assuming more water saturation means more cooling and lower mobility, *kh/μ*. It should be noted, that the total mobility of the fluids in-situ (water and oil, Figure 7) governs history matching of water injection. Applying this approximation provided reasonable history matching in both log-log (Figure 8, 'No Fault' case) and linear (Figure 10) scales.

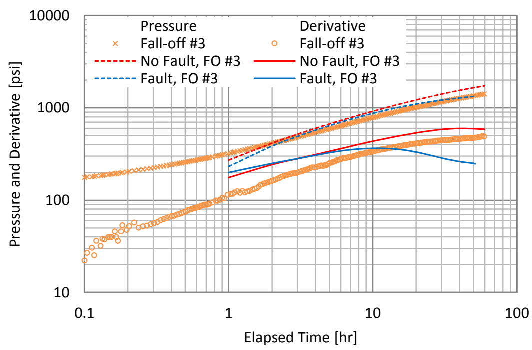

Figure 8 *Matching 3rd fall-off response: the models without and with conductive faults inter-well (Figure 1).*

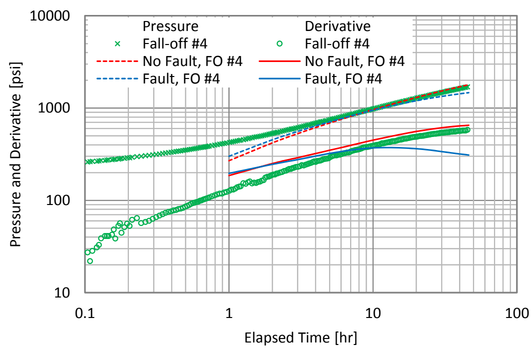

Figure 9 *Matching 4th fall-off response with the same models (Figure 8).*

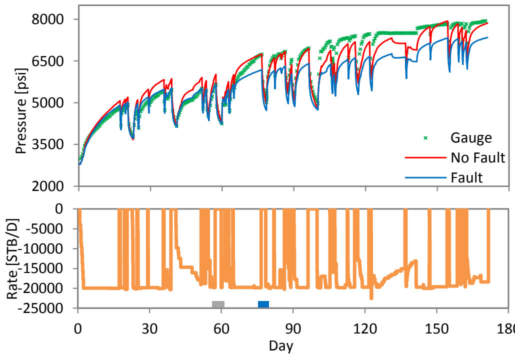

Figure 10 *History matching of the segment models (Figure 1) without and with faults.*

Seismic interpretations indicated faults in the inter-well area. The segment model was used to study a hypothesis that the wells could be connected to the faults, with faults having very effective (infinite) conductivity along the fault planes. However, the simulations of the historical period disconfirmed this hypothesis: presence of such a connection resulted in mismatch of both the pressure derivative (Figure 8Figure 9) and pressure build-up history (Figure 10). This may serve as an illustration of the value of integrating pressure derivative into history matching. Modelling connection to high-permeable features gave decline in the derivative (Figure 8,Figure 9) that was not observed.

Conclusions

The case described in this paper was used for illustration of the following thoughts:

- Widely available PDG data may be integrated into history matching of reservoir models.
- Time-lapse PTA and resulted history of well-reservoir parameters provide reasonable first guess for reservoir simulation, when a grid relevant for simulating main flow regimes is in use.
- The PDG data integration with combination of using pressure derivative as additional history matching parameter improves prediction capabilities of reservoir models via correct separation of well and reservoir effects and representation of flow patterns.

This paper used a rather simple example and did not cover 3D (multi-layer) simulations and gridding effects / issues related, which are of importance when combining PTA with full-field reservoir models and a matter for dedicated studies.

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