Novel Ways of Parameterizing the History-Matching Problem

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Novel Ways of Parameterizing the History Matching Problem

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Abstract

One of the challenges when making a history match study is to find an adequate parameterization for the reservoir model. The main assumptions of the geological characterization should be respect and the influence of parameters on the fluid flow simulation results should be taken into account. On the other hand, the number of parameters should be kept within reasonable bounds in order to make the process viable. In this work, three examples of novel ways to parameterize the history match problem will be shown. Two of them are real field cases and one is a synthetic case based on outcrop data. Common to all examples is the choice of parameters that are related to the geological model building process, such as the variogram in a geostatistical modeling or correlations between petrophysical properties (permeability x porosity, for instance). In this context, the use of a versatile history matching tool was essential, allowing for a quantitative evaluation for the quality of the match and for managing a larger number of parameters, when comparing to the traditional trial and error procedure. These examples show how the combination of a suitable parameterization with a versatile assisted history matching tool can improve both the quality and the efficiency of the history matching process.

Introduction

History matching is the process of modifying parameters in a reservoir simulation model, such as permeability and porosity, in order to make the model fit the production data previously observed in the field. Traditionally, this is pursued through a long and tedious process of trial and error, involving a qualitative judgment of the match. In general, the modifications in the model do not fully respect the assumptions made in the geological model building process, so that static and dynamic data are not incorporated in a systematic way. Also, many different solutions are possible, depending on the starting model and the reservoir parameters that will be modified. Due to these reasons, the history matching is usually the most complex and time-consuming task in a reservoir simulation study, requiring a lot of expertise and experience.

These difficulties have long been recognized and many techniques aiming to automate the process have been presented in the literature\textsuperscript{1-6} and, in the last few years, some assisted history matching tools have become commercially available. Common to most of these methodologies is the use of a least-squares objective function to quantify the misfit between simulated and observed data. This objective function can be expressed as

\[
O(m) = \sum_{i=1}^{Nobs} w_i \left( d_i^{\text{sim}}(m) - d_i^{\text{obs}} \right)^2 \tag{1}
\]

where \( m \) is the vector of reservoir parameters, \( d_i^{\text{obs}} \) and \( d_i^{\text{sim}} \) are the \( i \)-th observed data and corresponding simulated data, \( w_i \) is a weight and \( Nobs \) is the total number of observed data. In general, an optimization algorithm is employed in order to search for the \( m \)-vector that minimizes Eq. 1. Although these tools show much promise in improving the efficiency and quality of the history matching process, the trial and error procedure is still the rule in daily reservoir engineering practice. Among the reasons for this situation are the high computational costs involved in the optimization process and the fact that in many situations the primary difficulty is in the definition of the set of reservoir parameters to be used for a particular history match problem. The problem of finding an adequate parameterization for the reservoir model is usually not properly addressed by the current tools.

Three aspects should be taken into account when defining a suitable parameterization for history matching:

- respect of the main assumptions of the geological characterization;
- the influence of parameters on the fluid flow simulation results;
- the number of parameters, in order to make the process viable.

In this work, some examples of novel ways to parameterize the history match problem will be shown. In all of them, a versatile assisted history matching tool was used\textsuperscript{7}. This tool allows for controlling parameters in the geological/geostatistical modeling process, such as the variogram or correlations.

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between petrophysical quantities. It also incorporates the gradual deformation method. In this methodology, equiprobable geostatistical images are combined and the coefficients of the combination are calculated in order to obtain the best possible match with the production data. It also allows for managing a larger number of parameters, when comparing to the trial and error procedure.

The first example comes from a pilot production system, lasting for approximately one year. Production data were PDG data and water cut. In order to achieve a match with the production data, a reduction factor for vertical permeability as a function of NTG was introduced, and a parameter of this function was used in the optimization process.

In the second case, the main geological uncertainty is the presence of thin interzone shales. These shales were represented in the reservoir simulator as a Z-transmissibility multiplier map between simulation grid layers. This map was calculated as a function of shale thickness. Water cut was used to determine the geostatistical parameters for shale thickness generation and the coefficients in the multiplier versus shale thickness correlation.

The last example is a synthetic case based on outcrop data, where the presence of channels controls the fluid flow. Water rate data were generated using a fine model, while a coarser model, with additional uncertainties, were used for the history matching process. The channel distribution was parameterized through a threshold in the NTG map. Parameters from the variogram and the gradual deformation method were used to modify the facies distribution in order to better fit the water production data. Coefficients in the permeability versus NTG correlation were employed to further improve the match.

These examples show how the combination of a suitable parameterization with a versatile assisted history matching tool can improve both the quality and the efficiency of the history matching process.

Case Discussions

Case 1

This example describes a novel parameterization approach to history match bottom-hole pressure and water cut data by introducing a cell-by-cell reduction factor of the vertical permeability as a function of the net-to-gross (NTG) property. The history match progressed in several stages as new information was obtained and updated full scale reservoir simulator flow models became available.

General information

This case history pertains to a heavy oil (17 API) deepwater field (1000-1500 m) in Campos Basin. The reservoir is a gravel/sand-rich Maastrichtian turbidite formation with high porosity and permeability which overlays a thick aquifer. Oil viscosity is around 15 cp at bubble-point pressure (184 kg/cm²). The original oil in-place (OOIP) is estimated around 330 MM sm³.

A conventional transient well testing was run in the discovered well (Y-01) that showed productivity insufficient to guarantee economical hydrocarbon production. A horizontal well 1100 meters long (Y-02) was then proposed, drilled and tested. The test results showed a 10-fold productivity increase compared to the vertical discovered well. Two additional appraisal vertical wells were drilled (Y-03 and Y-04) but not tested.

An extended well test (EWT) on the horizontal well Y-02, producing to a FPSO, was proposed and approved by the regulatory agency. The EWT was designed to gather additional information not only on reservoir behavior (long-term productivity, aquifer strength, reservoir connectivity) but as well as on ESP artificial lift performance, flow assurance in such low temperatures, process plant and offloading efficiency. A permanent down hole gauge (PDG) was installed to continuously monitor the bottom-hole pressure. The EWT started in Oct. 2002 and lasts for 50 days. The EWT facilities and installations remained in location and the well Y-02 was allowed to continue to produce to the FPSO with pressure/flow rate data being continuously monitored, starting the pilot-production phase of the Y field. The FPSO left the location by the end of 2003 for maintenance and resumes operation in April 2004. Unfortunately, PDG signal was never reestablish therefore results shown here consider only data up to Dec. 2003.

First field flow model

Based on the four wells data, well logs, core samples, seismic data, stratigraphic and structural analysis were performed to build a 3D geological model and exported to a reservoir flow simulator. The full field numerical model has a corner-point mesh with 221,000 grid blocks, 141,000 being active. This first flow model is homogeneous, filled in with average properties values. The NTG property, for instance, is constant throughout the model, that is, all cells in the numerical simulator are set to a single value equal to 0.73. Only the major fault, which runs in NE-SW direction across the field, is represented in this first flow model. Initially this fault was assumed as a fluid flow barrier as the geological model assumed a different O/W contact for the western and eastern part of the field. The dynamic data was introduced into the flow model in steps: first, the pressure data from the conventional well test were history matched; then EWT pressure data was used; finally, PDG pressure and water cut data measured during the pilot production were added.

On matching the well test pressure data from wells Y-01 and Y-02 it was necessary to make local grid refinement around those wells so the transient behavior was reproduced accurately. The history match parameters were horizontal permeability (kxy), vertical permeability (kz) and skin factors. A very good agreement (not shown) was obtained for both test data with kxy = 1200 mD and kz = 120 mD. The well tests were not run long enough to show sensitivity to fault transmissibility so up this point the fault was considered as sealing to fluid flow.

We should make clear that test data were history matched, that is, the test flow rate schedule was used as input in the simulator and the results were compared to pressure measured in the field. No permeability or skin values obtained from conventional well test analysis were ever used in the numerical simulator as input value. However, the values obtained form history match were fairly consistent with the estimated values from well test analysis.
Using the permeability values shown above, the numerical model was also able to show a good agreement to the Y-02 EWT pressure data. EWT history match indicates that the field major fault is not sealing and there was some pressure support from the aquifer. Later, in-situ stress analysis also revealed that Y field faults were all open. From this point on, the numerical model was modified to a uniform O/W contact and the fault transmissibility was set equal to one (i.e., not sealing). Wells drilled a few months later confirmed this history match finding.

Formation water appears in well Y-02 in late September, 2003. The water cut shows a slow but steady increase of 1% per month. With the permeability values shown before and considering the major fault as non-sealing, this first numerical model was able to satisfactorily match pressure and water-cut data measured during the pilot production phase (not shown). In this last history match step no local grid refinement were used. Sensitivity analysis on the aquifer pressure support on the eastern portion of the field was performed but not conclusive. It seems that is necessary to reduce the aquifer strength right underneath the horizontal well trajectory by adding a tar mat layer next to the oil/water contact or, similarly, a somewhat continuous shale layer next to the O/W contact. Though the data was being matched fairly well, it was becoming increasingly clear that this first numerical model need revision.

It should also be mention here that the history match results described thus far were performed by “hand”, that is, the match was obtained by a trial-and-error process driven by “engineering judgment” only.

Second field flow model

As part of the field development plan, two new wells were drilled in October 2003 in the eastern region of the field. The wells Y-05 and Y-06 are pilot-wells for two horizontal production wells to be drilled later. These wells show that the field has a uniform O/W contact so there is no apparent contradiction by assuming the major fault as non-sealing. Wire-line formation test data taken in those wells show a uniform gradient across both oil and water zones, with pressure level lower than the original pressure profile. This means that there is good vertical connectivity in this portion of the field and the producing sands in well Y-02 are laterally connected to wells Y-05 and Y-06.

Upon the information obtained by the new wells as well as the information brought by history matching the first model, the 3-D geological model was revised and the fluid flow model was updated. The new mesh is also a corner-point with 448,000 grid blocks, being 75,000 active. Reservoir heterogeneity is introduced in this new model by 3-D NTG maps only. Petrophical properties, such as permeability and porosity fields, are not specified, and are to be determined by history matching the measured data. The reference case is represented by a NTG map obtained from kriging. A total of 10 NTG maps realizations were also generated by Boolean modeling (based on geological objects with appropriated parameters for the Y-field depositional environment). These additional maps were initially designed for production forecast uncertainty analysis. Figures 1 and 2 show, respectively, the kriging and one of the Boolean images for the NTG property.

Besides the major fault, a few others faults were also incorporate in this new model. Nevertheless, all faults are initially assumed to be non-sealing, that is, fluid flow is allowed to cross them.

To update the history match with this new simulation model it was decided not to workout everything from the very beginning in order to speed up the process. The match would only consider data obtained during the pilot-production phase, that is, conventional well tests and EWT data was not mistory matched this time. However, to be an acceptable match, the horizontal and vertical permeabilities, as well as skin factors, should remain relatively close to those values obtained from the first simulation model. The workflow followed three basic steps: (i) a direct simulation run using previously matched parameters values; (ii) a history match trial for the same group of parameters \( (k_{xy}, k_z, Y-02 \text{ skin factor and major fault transmissibility}) \); (iii) a second history match trial with a modified set of parameters (to be shown later).

To get acquainted with the new flow model, a direct simulation run was done for the base case (kriged NTG map). The parameters values where identical to the previous history match: \( k_{xy} = 1200 \text{ mD} \) and \( k_z = 120 \text{ mD} \). Figures 3 and 4 show a comparison of bottom-hole pressure and water cut data calculated by the simulator with the observed data over entire
pilot production phase. It can be seen that a very good match is obtained for the PDG data only; the simulator predicts water production in the Y-02 well much earlier and water cut growth much faster than observed in the field.

Figure 3: Well Y-02 Bottom-hole Pressure before history match; NTG krigging image.

Several attempts were made to history match the base case model using the same set of parameters \((k_{xy}, k_z, \text{Y-02 skin factor and major fault transmissibility})\) without successful. We were not able to get a satisfactory match on pressure and water curves simultaneously. Other trials were performed with a different NTG map taken from the set built by the Boolean modeling to rule out any artifact introduced by the kriging image generation. The results were identical: could not match both curves simultaneously.

To control the water production one may be tempted to modify the oil-water relative permeability curves in order to delay water production in well Y-02. It was considered that there were many things less known to change first than data that has obtained through several laboratory displacement experiments.

It is worth-while to mention that the numerical simulator used in this work modify the gridblock transmissibility in the \(x-y\) plane as well as it porous volume as function of the gridblock NTG automatically. On the other hand, gridblock vertical transmissibility is not affected by NTG value.

Therefore, it was decided to somehow penalize the vertical permeability. One alternative is to use the NTG map as a vertical transmissibility multiplier map, so one would get a fixed linear reduction much like the numerical simulator internally handles the horizontal transmissibility. However, it is felt that the NTG property should have a stronger impact on the vertical transmissibility. This is in accordance with a previous detailed study on heterogeneity impact on fluid flow, which was based on upscaling fine simulation models constructed from outcrop data\(^1\). It was decided to introduce a vertical permeability reduction as a function of the net-to-gross as part of the history matching process. In this work we applied the following equation to penalize the vertical permeability:

\[
k_z(i,j,k) = k_{z,base} \left( \frac{ntg(i,j,k) - ntg_{Cutoff}}{1 - ntg_{Cutoff}} \right),
\]

where \(k_z(i,j,k)\) represents the new vertical permeability value for gridblock \((i,j,k)\), \(k_{z,base}\) is a reference vertical permeability value and \(ntg(i,j,k)\) is the net-to-gross ratio in the gridblock of coordinates \(i,j,k\). The parameter \(ntg_{Cutoff}\) represents a cutoff value below which the vertical permeability \(k_z(i,j,k)\) permeability is set to 0.0001 mD. The correction behind Eq. 2 can be better understood by looking at Figure 5.

The above methodology was implemented into the history matching with aid of a history matching software\(^7\). As this procedure is not a standard one, the tool must be flexible enough to handle such particular applications. It should be stressed that this application would not be practically viable without this software assistance.

Thus, for this second flow model, the history matching parameters for a given NTG map now become \(k_{xy}, k_{z,base}, \text{well Y-02 skin factor and ntg}_{Cutoff}\). For the kriged NTG map, for instance, the optimum values obtained were \(k_{xy} = 1355 \text{ mD, } k_{z,base} = 131 \text{ mD and ntg}_{Cutoff} = 0.243\). Note that the permeability values are a bit higher than the values obtained by the first flow model history match but still within an acceptable limit.

Figure 6 shows the simulated bottom pressures with the optimum values. Figure 7 presents the match for the water cut data. In both figures the agreement is excellent. These figures show that the technique based on penalizing the vertical
permeability as a function of the NTG was a successful strategy to history match the Y-02 pilot production data.

Figure 6: Well Y-02 Bottom-hole Pressure history match; NTG krigging image.

Figure 7: Well Y-02 Water Cut history match; NTG krigging image.

The same history match technique was applied to the other 10 NTG realizations, resulting in matches with quite similar quality of those presented in Figures 6 and 7. The history match obtained for the NTG Boolean Image #02, for example, can be seen in Figures 8 and 9.

Figure 8: Well Y-02 Bottom-hole Pressure history match; NTG Boolean image #02.

Figure 9: Well Y-02 Water Cut history match; NTG Boolean image #02.

Though we were able to history match the pilot production data with all 11 NTG maps, some images got a too high $k_{base}$ value (210 mD) or an extremely high value for $ntg_{cutoff}$ (0.9). Those images were discarded. The remaining ones were used for production forecast uncertainty and economical analysis or for different development plans scenarios comparison such the one described in Ref. 12.

Case 2

The second example is a deep offshore field in Campos Basin (unconsolidated turbidite sandstone from Oligo-Mioceno) with 1,012 Mm$^3$ STOIP and area of 150 km$^2$. The average thickness is 30 m, with high porosity (0.30). Permeability varies between 1 and 10 D and the net-to-gross ratio is around 86%.

The reservoir does not have any pressure support mechanism and the saturation pressure is near the reservoir initial pressure. Oil density varies between 18 and 25 API, both horizontally and vertically. Viscosity varies from 2.5 to 8 cP.

There are four main production zones which have good hydraulic continuity. The secondary recovery is based on water injection. Currently, there are 83 producers and 45 injectors, including 27 horizontal wells. The field has twenty years of production history.

The simulation model is a 200 x 240 x 14 corner point grid, with cells of 100m x 100m. For the water cut history matching process, the model was divided into five sub models. Each one of these sub models can be simulated independently, as long as the flux through the boundary is taking into account. This kind of approach is useful to reduce simulation time, especially for large models.

In this reservoir, the main heterogeneity is the presence of thin shales layers that occur intercalated to the reservoir, mainly in the interface between zones (see figure 10). These shales are essential to the fluid flow behaviour, since they control vertical fluid flow. There is a high uncertainty related to the horizontal extension and the seal effectiveness of these shales. In the simulation model, these interzone shales are not represented by layers, but as a reducer in the vertical transmissibility between simulation grid layers. This vertical transmissibility multiplier was calculated as a function of the
shale thickness in each cell. In order to generate the shale thickness distribution, 2D geostatistical simulation conditioned to well data was performed. During the history matching, the relevant parameters in this process were adjusted interactively to fit the water cut data.

Figure 10 – Interzone shales in the model simulation.

A sequence of parameter estimation problems was solved before a good match for the water cut history was obtained. In the first step, the aim was the adjustment of the horizontal extension of the shales. For that purpose, some parameters of the 2D Gaussian simulation, which generates the interzone shale thickness distribution, were used as inversion parameters. The parameters were the mean value, the anisotropy and range of the Gaussian variogram.

In the second step, the coefficients of the correlation between vertical transmissibility multiplier \((\text{MultZ})\) and shale thickness \((h_{\text{shale}})\) were used to adjust the seal effectiveness. When the shale thickness is below a certain threshold value \(\text{PARAM1}\), there is no impact in the vertical flow, so that the following relationship holds

\[
\text{MultZ} = 1, \quad h_{\text{shale}} < \text{PARAM1}
\]  

(3)

In the same way, when the shale thickness is above a certain threshold value \(\text{PARAM2}\), the presence of shales behaves as a vertical flow barrier, so that the following relationship holds

\[
\text{MultZ} = 0, \quad h_{\text{shale}} > \text{PARAM2}
\]  

(4)

If the shale thickness laid between \(\text{PARAM1}\) and \(\text{PARAM2}\), the vertical transmissibility multiplier follows the equation

\[
\text{MultZ} = \cosh \left( \frac{5.3}{\text{PARAM2} - \text{PARAM1}} \left| h_{\text{shale}} - \text{PARAM1} \right| \right), \quad \text{PARAM1} < h_{\text{shale}} < \text{PARAM2}
\]  

(5)

Figure 11 shows a plot representing the \(\text{MultZ} \times h_{\text{shale}}\) correlation.

Figure 12 presents the vertical transmissibility multiplier maps obtained by the optimization process. Figure 13 shows a cross plot of water cut for the wells in the submodel between the observed data and the simulation result of the initial model. Figure 14 shows the crossplot for observed data and the simulation result of the matched model. Comparing figures 13 and 14, one can see that modifications in the model resulted in a great improvement for the water cut match. Figures 15 to 18 shows the match obtained in the water cut curve for some selected representative wells.

Figure 11 – The \(\text{MULTZ}\) versus \(h_{\text{shale}}\) correlation.
Figure 13 - Crossplot of water cut for the production wells between production data and the simulated data of the initial model. Perfect fit falls on the 45° line. Slashed lines represents 10% deviation form the perfect fit.

Figure 14 - Crossplot of water cut for all production wells between production data and the simulated data of the model obtained by the match.

Figure 15 – Water cut match for well PROD2. Red line is the observed data and blue line is the simulation result.

Figure 16 – Water cut match for well PROD7. Red line is the observed data and blue line is the simulation result.

Figure 17 – Water cut match for well PROD84. Red line is the observed data and blue line is the simulation.

Figure 18 – Water cut match for well PROD112. Red line is the observed data and blue line is the simulation result.

Case 3
The third example is a synthetic case based on outcrop data, from Brazil and abroad. These data were collected, compiled and treated, both qualitatively and quantitatively, generating a reliable data base of geometrical parameters of depositional elements. The model, which will be referred as the base model, reproduces a turbidite system deposited in deep water, the most important reservoir type found in Brazilian coastal basins. The depositional elements modeled were channels, lateral deposits to the channels (denoted spills) and hemipelagical shales, which represent pauses in the sedimentation process. The petrophysical parameters (porosity
and permeability) were attributed from correlations against the net-to-gross variable (NTG), and the values are within the typical range found in some of the Brazilian reservoirs. The porosity versus NTG correlations used were

\[ \phi = 0.17 \times NTG + 0.18 \]

(6)

for the channels and

\[ \phi = 0.10 \times NTG + 0.10 \]

(7)

for spills. For horizontal permeability, the correlations used were

\[ \log(K) = 0.7 \times NTG + 3 \]

(8)

for the channels and

\[ \log(K) = 1.0 \times NTG + 2 \]

(9)

for spills. For the vertical permeability a value of 30% of the horizontal permeability was assumed. The base simulation model was built with a 217 x 275 x 6 mesh (352,492 active cells), and twelve well locations were defined, including seven producers and five water injectors, taking into account the continuity and permo-porosity features of the reservoir. The base model was simulated for a period of ten years, and the water cut in the producers was used as the real historical production of the study. To represent measurement errors, a ten percent noise level was added to the simulated results.

To reproduce the typical conditions of model construction in real situations, a second model was built to represent the reservoir. For that purpose, the reservoir was cut into three units, assuming the same geological properties for all layers in the same unit. The first unit was composed of the three first layers, the second one was composed of the fourth and fifth layers and the last unit was the sixth layer. Data from the twelve wells were used and, for each unit, a NTG map of the most representative layer, slightly modified from the fine model, served as a seismic attribute map. In a first step, a facies modeling was done, trying to estimate, from well data and NTG map, the configuration of channel facies and facies marginal to the channel (spills). In a second step, petrophysical parameters were attributed using the same correlations as in the fine model. This simulation model used a coarse grid. The mesh is 43 x 55 x 6 (14,168 active cells) and the wells were located at the same geometric position as in the base model. As a result of these modifications, a great uncertainty with respect to properties and spatial distribution of the channels was added. This model will be referred as the initial model. The horizontal permeability maps for the units are shown in Figure 19.

The history matching of the water cut data consisted of three steps:
1. Determination of variogram parameters for the facies distribution;
2. Gradual deformation for the facies map determination;
3. Adjustment of the parameters in the log K x NTG correlation.

In all three steps, an assisted history matching tool was used. In the first step, a 2D truncated Gaussian simulation of lithofacies was done for each unit using well data as conditional data, since the presence of channels controls the flow. The regression parameters were the range, the main anisotropy and the azimuth of the exponential variogram. Table 1 shows the optimal values and the range of search of the parameters. In order to further improve the match, a second step made a fine adjustment in the facies distribution using the gradual deformation method. In this methodology, equiprobable geostatistical images are combined and the coefficients of the combination are calculated in order to obtain the best possible match with the production data. Three initial geostatistical images were used for each unit. In the third step, the facies map created as a result of the two first steps was kept fixed and the coefficients of the permeability versus NTG correlation were employed to achieve the match. The same kind of correlation used in the base model (equation 10) was employed,

\[ \log(K) = A_{ij} \times NTG + B_{ij} \]

(10)

where the i index represents the units (unit 1, unit 2, unit 3) and the j index represents the facies type (1 for channel and 2 for spill). In order to keep the number of parameters manageable, a series of regressions was done, focusing on channel and spill parameters, as well as coefficients A and B.
in different optimizations. Table 2 and 3 show the initial values, the range of search and the optimal values achieved for each parameter. The permeability map for the units for the matched model are shown in Figure 20 and the results of the water cut match for each well are presented in Figures 21 to 26. Water cut plot for well PROD6 is not shown because, during the simulation period, there is no water production for this well, both in the base model and the matched model. The match was good for most of the wells.

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Table 2 – Optimal value, initial value and range of search of the parameters in equation 10 for channels.

<table>
<thead>
<tr>
<th>Channels</th>
<th>$A_{i}$</th>
<th>$B_{i}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit $(i)$</td>
<td>Min</td>
<td>Max</td>
</tr>
<tr>
<td>1</td>
<td>0.3</td>
<td>0.9</td>
</tr>
<tr>
<td>2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 3 – Optimal value, initial value and range of search of the parameter $B$ in equation (10) for spills.

<table>
<thead>
<tr>
<th>Spills</th>
<th>$B_{i}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit $(i)$</td>
<td>Min</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td></td>
</tr>
</tbody>
</table>

Figure 20 - Permeability map for the geological units in the model obtained by the match.

Figure 21 – Water cut match for well PROD8. Red line is the historical data, green line is the initial model and blue line is the matched result.

Figure 22 – Water cut match for well PROD12. Red line is the historical data, green line is the initial simulated result and blue line is the matched result.
Conclusion

Parameterizations of reservoir models, supported by the basic assumptions adopted in the geological model building process, were successfully used for history matching in three examples, including two field cases and a synthetic case based on outcrop data. In all cases, a reasonable match was obtained without violating the main guidelines used when building the geological model.

The use of an assisted history matching tool was decisive for making the overall procedure viable, allowing for handling a larger number of parameters when comparing to the traditional trial and error procedure. The versatility of the tool was also essential, since it made possible changing parameters related to the geological modeling process, that are not directly available in the simulator input data file.

The examples discussed in this work show that the combination of a versatile assisted history matching tool with proper parameterizations of the reservoir simulation model can generate history matched models that are not in conflict with the main assumptions of the geological model building, improving both the quality and efficiency of the history matching process.

References
