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An Improved Regional Segmentation for Probability Perturbation Method

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Summary

Conventional history matching methods do not consider seismic and geologic continuity data. Caers (2002) introduced a novel history matching method named Probability Perturbation Method (PPM) by extending the multiple-point geostatistics framework to production data; The method's key point is to perturb the underlying probabilities used to generate properties and not the properties directly.

In single region PPM, one perturbation parameter is used for the entire reservoir. However, in multi-parameter perturbation, different amounts of perturbation are applied to different parts of reservoir

In our method, a weight factor is assigned to each point (well location) in a way that the volume of each generated region is proportional to the rate of well located inside the region. In other words, volume divided by rate is equal for all regions. Therefore, the question is how to find the weight factors. A set of equations is formed and the solution is found by an iterative method. In each time step, the weight factors and consequently regions could be updated based on well rates. The Voronoi diagram has already been used for defining regions, however the novelty of this work is that defined Voronoi regions are proportional to rate and update dynamically without flow simulation.

Introduction

History matching is an important task in reservoir modeling workflow process. The overall objective of reservoir modeling is to reduce the uncertainty in the production forecasts by including all available data into the model. Most importantly, the model must be able to match the history while preserving geological data.

Most traditional history matching methods such as conventional gradient-based methods are based on some forms of trial and error schemes. These methods cannot usually preserve the geological continuity of the facies. Caers (2002) introduced a novel history matching method named Probability Perturbation Method (PPM) by extending the multiple-point geostatistical framework to production data. PPM is a data integration framework to integrate the observations while being constrained to prior geological data. The heart of this approach is to algorithmically perturb the underlying probabilities used to generate the reservoir properties (i.e. facies) and not the properties directly. PPM relies on the following simple, but key, idea: In order to maintain a specific geological continuity during history matching, we propose to perturb an initial geostatistical realization in a geologically consistent fashion (i.e., consistent with the geology depicted in the training image). Instead of perturbing directly an initial realization, we perturb the probability model that is used to generate that initial realization. Moreover, we make sure that after the geostatistical realization generated with the perturbed probability is still consistent with the geological continuity of the training image. (Caers, 2003). PPM generally consists of two loops; an outer loop and an inner loop. In the outer loop, the random seed and in the inner loop, rD or the perturbation parameter are changed. The inner loop makes small perturbation between two equiprobable realizations while the outer loop makes larger perturbation.

In the single region PPM, one perturbation parameter is used for the entire reservoir domain. However, the reservoir response can be influenced by local geological variations that can produce completely dissimilar behaviors in different parts of reservoir. Therefore, the history matching quality for some wells in one area might be deteriorated while the method tries to match the data globally from other areas. This in turn can dramatically reduce the speed of the history matching convergence. However, in multi-region perturbation, different perturbations are applied to different parts of the reservoir. Therefore, the regions with matched production are remained unchanged while the regions with unmatched production are perturbed. This is obtained without creating discontinuities in the geological properties of the model (Hoffman, 2005).

The first step in regional perturbations is to segment the reservoir model into distinct non-overlapping regions close to the wellbores. The regions could be defined from geological information, streamline simulation, or simply from the engineers' judgement (Bissel, 1994; Milliken, 2001). Note that although streamline simulation is an appealing approach, it still needs to perform the flow simulations to define the streamline-based regions which may not be always feasible. We propose a method that can efficiently improve reservoir segmentation for multiple-region PPM. This segmentation method improves convergence efficiency relative to single region method. Unlike streamline-based method, this method is not flow-based.

Dynamic Weighted Voronoi Segmentation Method

Voronoi diagram is partitioning of a plane into regions based on distance to points in a specific subset of the plane. In our application, that set of points correspond to the well locations. A weighted Voronoi diagram is the one in which the function of a pair of points to define a Voronoi cell is a distance function modified by multiplicative or additive weights assigned to generator points. A power diagram is a weighted Voronoi diagram in which a weight defined from the radius of each circle is added to the squared distance from the circle's center.

However, using a Voronoi diagram without any weight does not account for the wells that drain higher volume of the reservoir. Therefore, in our method, we propose to define a weighted Voronoi segmentation algorithm in which a weight factor is assigned to each point (well location) in a way that the volume of each generated region is proportional to the rate of well located inside the region. In other words, volume divided by rate is equal for all regions. Therefore, the question is how to find the weight factors. The process is iterative in nature; in other words, distance-based weight factors are assigned to the points (well locations). Then the power Voronoi diagram is generated, the volume of each region is computed, and finally the ratio of each region's volume to the rate of well located inside the region is calculated. If all the ratios are the same, the weight factors are acceptable, otherwise the process is iterated. In each production time step, the weight factors and consequently regions can be updated based on well rates. This iterative method is very quick and robust. The Voronoi diagram has already been used for defining regions, however the novelty of this work is that defined Voronoi regions are proportional to rate and update dynamically. The Voronoi diagram is then used to apply the dynamic multi-region PPM for dynamic updating of the geological model using production data at each timestep.

Example

In this paper, we consider a two-facies model with 80 grid blocks in x and y directions. The sand facies has a permeability of 100 md while the shale's permeability is 0.03 md. The reference model's domain and the corresponding well locations are shown in Figure 1. There are 5 wells, one injector in the center of the model and four producers. The injector well is connected to all producing wells, however the connection strength is different among them (Figure 2A). The connection between injector and producer 1 is narrow, however it has high effect on pressure maintenance. The red circles in Figure 2 display the bottleneck areas that control the connectivity of the facies which we have to reproduce during history matching process. This challenging reference model is selected intentionally to evaluate the performance of multiple-region and single-region PPM. The rates and bottom hole pressures at the producers and injector will be matched to the reference's response. In the geostatistical applications, a random seed is used to control the randomness of the realizations. The initial realization and the random seeds for both methods are the same to make better comparison. The objective function is defined as the sum of squared relative errors between the reference rates and the simulated rates as well as between the reference bottom hole pressure and the simulated bottom hole pressure for all the wells. A random white noise was added to the reference production data. The oil rate is set to 105 (m3/d) for producers 1, 2 and 4, and 100 (m3/d) for producer 4. The water injection rate is 500 (m3/d). The dynamic Voronoi regions are defined based on well rates, well locations and reservoir boundary. Figure 1 shows the segmentation of the original model at one timestep using the weighted Voronoi segmentation algorithm. The volume of each region is proportional to the rate of well located inside the region.

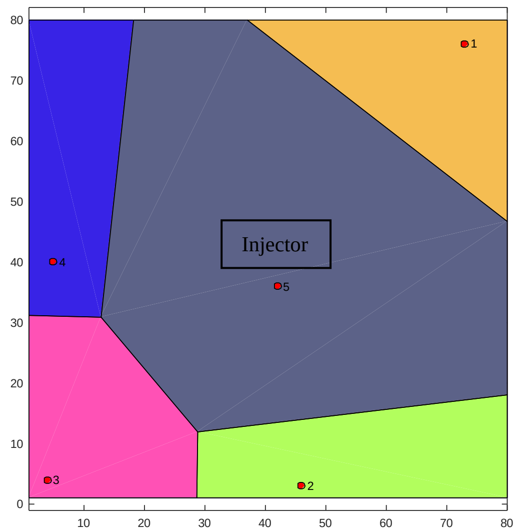

***Figure 1**. Region geometry defined by dynamic weighted Voronoi polygons*

The results of history matching using multiple-region (proposed dynamic weighted Voronoi method) PPM and single-region PPM are discussed below.

Figure 2 shows the facies realizations of the best matched models obtained from multi-region and single-region PPM. In the single-region PPM no segmentation occurs and the whole model is updated at once using a single parameter that controls the configuration of the facies in the model. Figure 2 shows that the multiple-region PPM can capture the important connections between the wells. In particular, the injection well is connected to four production wells and it leads to pressure maintenance and consequently more recovery factor. However, the connection between injector and producer 2 has been missed in single-region method. In addition, the connection between the injector and producer 3 is narrow. These missing connections will cause the rate decline as depicted in Figure 3.

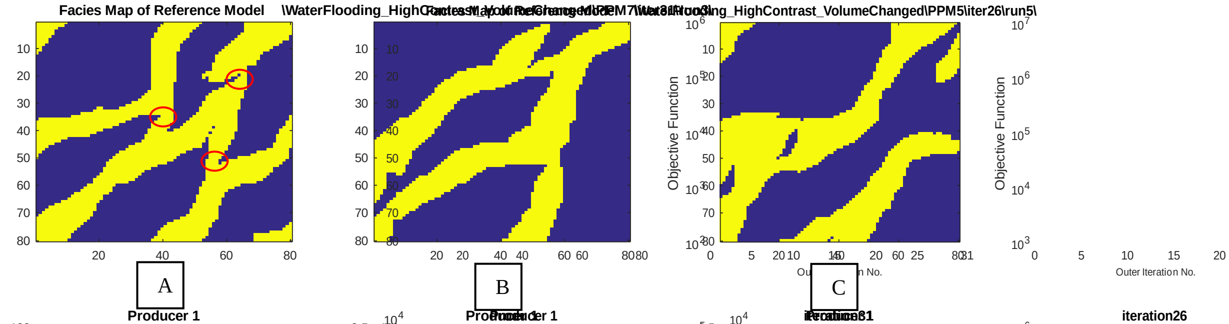

Figure 2. *Facies distribution of the reference model(A), facies realization of the best match of multiple-region (proposed method) PPM (B), and facies realization of the best match of single-region PPM(C)*

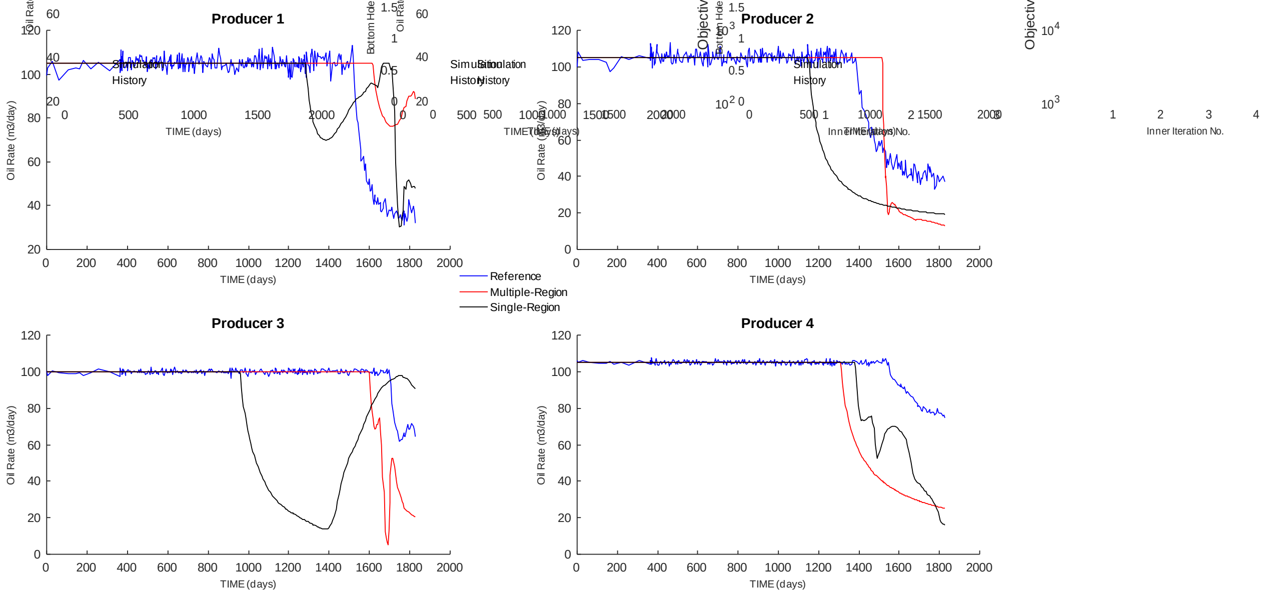

Figure 3*. Well oil production rate of producers for reference model, multiple-region (proposed method), and single-region PPM*

Figure 4 shows the convergence performance of the multiple-region and single-region PPM. The figure shows a better convergence for the proposed multi-region PPM. It is speculated that the efficiency of the regional perturbation should increase further over the single-region method when the geology of the model is significantly different spatially. This is intuitively true, as multi-region PPM offers a higher flexibility to perturb the local regions for a better history matching quality. Figure 4 shows that most of the objective function reduction happens at initial iterations, however numerus additional runs are required to match to the lower objective function. Large perturbations at initials and then small changes are required to get an exact match.

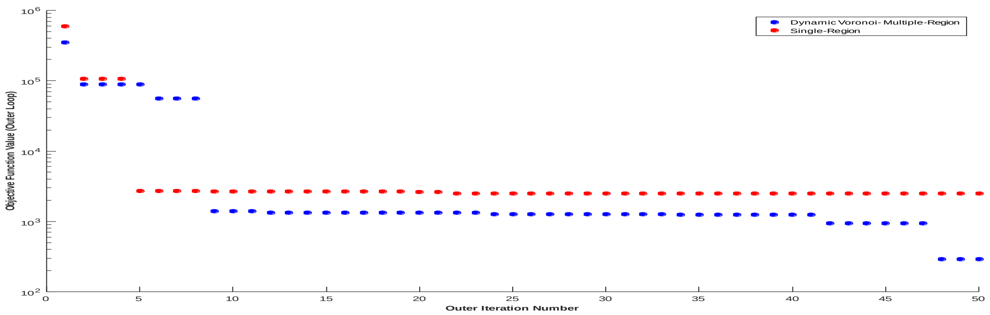

***Figure 4**. Objective function decrease for outer iteration*

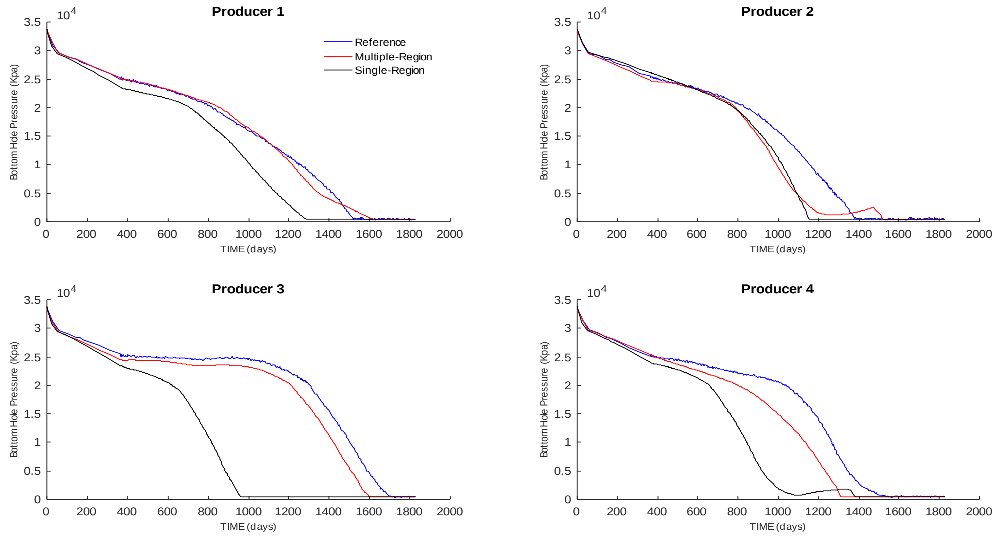

***Figure 5**. Well bottom hole pressure of producers for reference model, multiple-region (proposed method), and single-region PPM*

Conclusions

In this paper, we present a novel method to improve the history matching quality by a geologically consistent PPM. A new method has been proposed to systematically define multiple regions to employ the PPM. The regions' volumes correspond to the drainage volumes of wells. The regions are dynamically updated at each time step without flow simulation. The regions add additional flexibility to the history matching framework as it allows local perturbations of the facies distributions while the overall geology is kept consistent. This method improves the convergence efficiency and the matched quality. History matching with regional method is more efficient than the single-region method especially when the reservoir geology is complex.

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