Uncertainty Quantification with Multiple Scenarios for Deformation of Reservoir Structure and Evolution of Petrophysical Properties

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Abstract

Uncertainty quantification for reservoir responses at an early stage of development is necessary to manage natural resources economically and sustainably. Geological interpretations of a reservoir’s structural deformation, as well as how reservoir rocks have accommodated the deformational loading, are both uncertain; fractures increase this uncertainty. We propose a geostatistical modeling framework to capture the effect of both sources of geological uncertainties: how the reservoir has been deformed, and how the rock has accommodated the deformation. We also investigate their effects on reservoir property modeling, and on uncertainty of reservoir flow and seismic responses. The evolutions of reservoir properties under specific scenarios of geological uncertainty can be modeled as transfer relations between property values at the syn-depositional domain and post-depositional domain. The workflow uses restored values of the observed hard data as conditioning data in the geostatistical simulation (back-transformation), and changes the realization properties considering the deformation history (forward transformation). We applied the proposed workflow to a synthetic reservoir, to point out the pitfalls of conventional geostatistical modeling practices that do not account for these sources of deformational and accommodation uncertainties.

Introduction

For reservoirs with relatively large structural and deformational complexity, reservoir forecasting and uncertainty quantification becomes more difficult, as governing conditions of reservoir characteristics vary within the reservoirs. For example, the Suban gas field case in Indonesia shows fracture orientations, and its flow characteristics in one region are totally different from those in another region within the same formation, but at a different structural location (Hennings et al., 2012). Recently, many studies have tried to link structural deformation of the reservoir structure with spatially varying sub-seismic fractures (Suzuki et al., 2005; Lohr et al., 2008; Maerten and Maerten, 2006). In reality, structural geometry extracted
from seismic data is uncertain (Thore et al., 2002; Li and Caers, 2014). Even assuming the reservoir structure has one geometry, different assumptions on boundary loading configuration and different governing conditions on restoration analysis may give different stress-strain estimations (Lewis et al., 2007; Mallet, 2004). Thus, uncertainty on how the reservoir has been deformed becomes an important aspect of reservoir forecasting by impacting reservoir properties at different locations. Unlike fractures, how structural deformation may affect matrix reservoir properties such as porosity and permeability has not been investigated widely. A study on a CS field in Indonesia shows that even in a naturally fractured reservoir, areas with no fractures may give the highest productivity within the field (Paul et al., 2009). Thus, matrix properties cannot be overlooked even for naturally fractured reservoirs.

Previously, we proposed a geomodeling workflow to populate reservoir properties while considering the geological deformation of the reservoir (Shin and Mukerji, 2013). In this report, we extend the workflow to include not only the uncertainty from the deformation of reservoir structure, but also the uncertainty from reservoir property evolution, with different scenarios for how the rock has accommodated the given deformation. An application of the workflow on a synthetic fractured reservoir is demonstrated. Multidimensional scaling (MDS) techniques have been successfully used on geological scenario uncertainty (Park et al., 2013; Caers et al., 2010). To test the impact of different assumptions on structural deformation and reservoir property evolution, seismic and flow responses from multiple scenarios will be compared using MDS techniques.

Motivation

Uncertainty on Reservoir Structure Deformation

Restoration or retro-deformation analysis allows one to link the current structural geometry of a reservoir with its syn-depositional geometry (Mallet, 2002; Caers, 2005). Since this approach gives quantitative information on how the reservoir may have been deformed, many methodologies have been proposed to utilize strain/stress information from the restoration analysis for estimating sub-seismic faults and/or fractures (Suzuki et al., 2005; Maerten and Maerten, 2006; Lohr et al., 2008). Previous work used a single restoration analysis for estimating faults and fractures. Since restoration analysis is a manual and/or numerical optimization process based on some governing rules, different principles or different numerical algorithms may lead to different results (Mallet, 2002). Even in a case when kinematic displacement is identical, different boundary loading conditions may lead to different geomechanical history (Lewis et al., 2007). As a consequence, using a single interpretation of
deformation analysis may lead to underestimation and bias in uncertainty quantification. Thus, it is important to investigate how different interpretations of structural deformation may impact reservoir responses.

**Uncertainty on How the Rock has accommodated the given Deformation**

Different rocks may accommodate even identical deformations in different ways. The microfabric elements in rocks, such as mineral shapes, pore shapes, fractures, and deformation bands, change over time due to changes in the geological environments – e.g. geometry changes of structural shapes, stress/displacement loadings, and chemical environment (Siegesmund et al., 1999). For geomodeling purposes, these factors may be grouped into matrix properties and fractures/deformation bands. When rocks behave in a ductile manner with higher compliance to deformation, it may lead to rearrangement of grains and pores, which leads to changes in matrix properties. On the other hand, if the rock behaves in a brittle manner, it may develop fractures. For instance, two independent studies used the Distinct Element Method (DEM), which uses spheres or circular cylinders as representations of mineral grains, to simulate how the synthetic rock behave by vertical compression. They produced significantly different results, which represent different geological process. One experiment that did not consider cementing among grains in the DEM simulation gave rearrangement of grains and pores to accommodate vertical loading (Antonellini and Pollard, 1995). The other study, which does consider cementing – merely using a cut-off tensile stress to let two grains fall apart – produced vertical fracture developments as vertical loading increased (Bruno, 1994). The first result may be a representation of the deformation of soft rock, while the later one may be a representation of stiff rock. If this rigorous approach can usefully link the deformation of rock with faults/fractures, the same approach must be considered to link the deformation and changes in the matrix properties, as we proposed in previous work (Shin and Mukerji, 2013).

**Methodology**

**Reservoir Property Transformation between Post-Depositional and Syn-Depositional Domains**
Figure 1: Reservoir property transformation as pre- and post-process of geostatistical simulation. The conventional process was limited to re-location of data points between two different physical domains (figures are modified from images by Caers (2005)). We propose to use not the observed values, O, as in geostatistical modeling, but the restored values, O*, by considering the geological understanding of deformation and accommodation. Simulated values, S*, are also changed into deformed values, S, in the proposed approach.

Figure 1 depicts the main idea of the proposed workflow. We propose not only to use the results of restoration analysis to map one coordinate to another, but also to change the reservoir properties in a representative way, to model our understanding of the geologic history of the reservoir. Let assume that any observed geological properties in the present time are expressed by “O”. The observed values, O, may have experienced a series of geological processes, which may have changed the values of geological properties over a geological period of time. If we express these changes in reservoir properties as a transfer function, “f”, and the corresponding values of observed reservoir properties in a previous geological time as “O*”, we may express the relation between the values of observed reservoir properties at O with those of the previous condition O*, as in Equation 1, where “f⁻¹” means an inverse of a geological process.

\[ O^* = f^{-1}(O) \]  

(1)

In reality, it would be hard to figure out the exact geological processes impacting reservoir properties. But it would be possible to build a couple of scenarios on what type of geological events may have played key roles in the evolution of reservoir properties. If we want to build a transfer function defined by the structural deformation of reservoirs, kinematic deformation information can be extracted from strain analysis (Mallet, 2002; Pollard and Fletcher, 2005). To
use deformation induced stress in the transfer relation, deformation related stress analysis can be done either using strain analysis with elasticity, or by conducting geomechanical restoration analysis rather than kinematic restoration (Maerten and Maerten, 2006). Once the transfer relations are defined, we can restore the observed values into the past condition by Equation 1. We propose to use restored reservoir properties as hard data on any geostatistical simulation when populating reservoir realizations (Equation 2). To be consistent with the current geological condition, the simulated values, $S^*$, can be easily transformed into the current condition, $S$, by using the transfer relation (Equation 3).

$$S^* = \text{geostat.}(O^*)$$  \hspace{1cm} (2)

$$S = f(S^*)$$  \hspace{1cm} (3)

A conventional “copy and paste” approach can be expressed by Equation 4. In the viewpoint of the proposed workflow, if we follow conventional practice, we are implicitly assuming either that reservoir properties do not change by reservoir deformation, or that the degree of changes over the entire domain is uniform.

$$O^* = O \quad \& \quad S = S^*$$  \hspace{1cm} (4)

**Uncertainty in Reservoir Property Evolution**

The function “$f$” in Equations 1 & 3 can be any transfer relation to link the physical properties of current status to the physical properties of any interested past geological moment, which can be parameterized by measurable values from an available dataset. It does not necessarily have to be the exact way that the reservoir properties have evolved. The important thing here is to capture the most important geological events that geoscientists are considering in the transfer relations, in a simple yet representative way. As long as the observed values are conserved from consecutive forward and backward transfers, and the forward and inverse of the relations are bounded within physically meaningful ranges, any transfer relations can be postulated. Different transfer relations can be representations of geological scenarios of how the reservoir properties have been deformed. In the following synthetic examples, we are going to focus on strain-stress distribution from structural deformation, and the timing of cementation compared with the timing of structural deformation.

**Uncertainty in Structural Deformation**

If different geologists have different views on structural history of fields, or different
assumptions about how rocks across fault surfaces might behave, or if they used different automated numerical algorithms when conducting their analysis, they may end up with different restoration results. In this report, we are going to use spatially varying strain components from deformation/restoration vectors to control fracture direction and fracture intensity, and dilatation to restore/deform matrix porosity. Thus, different scenarios of structural deformation may impact fracture realizations and their porosity in each model.

**Application to a Synthetic Reservoir Case**

**A Synthetic Reservoir: Structural Geometry**

![Figure 2: Structural geometry of a synthetic reservoir. Top – top view of geometry. Bottom – side view of geometry. Red dots – exploratory wells. Blue dots – exploratory wells converted to injectors.](image)

Figure 2 shows the geometry of a synthetic reservoir – top and bottom layers, fault surfaces, and well locations. We used Paradigm SKUA to generate this synthetic structure. The surfaces for horizons and faults are optimized from manually digitized points.

**Multiple Geological Scenarios of Structural Deformation**

As discussed in the motivation section, different restoration methods assume different governing rules on how horizons have been displaced. In real cases, we can never know exactly how the structure has been deformed. But for this example case, we are going to apply two different restoration methods to construct depositional grids, and choose one of them as the true deformation of the structure.
Figure 3: Reservoir structures colored by dilation from deformational strain. Left – deformation scenario A. Right – deformation scenario B.

Figure 3 shows dilatation distributions from two different deformation analyses. Dilatation is the summation of Eigen strain values which are obtained from deformation analysis (Equation 5). It can be a representation of the fractional changes of the volumes.

\[
dilatation = \sum_{i=1}^{2} \varepsilon_i
\]  

(5)

Scenario A results from a flexural slip algorithm which preserves area and line length, by allowing strain discontinuity across faults and horizons. Scenario B is conducted under a minimum-deformation principle, which minimizes strain discontinuity over the area (Mallet, 2002). We choose scenario A as the true deformation history of the synthetic reservoir. It is noteworthy that we arbitrarily chose one restoration principle to represent the true deformational history of the synthetic reservoir. This does not say anything about which scenario is more geologically realistic.

**Multiple Geological Scenarios in Reservoir Property Evolution**

Figure 4: Geological scenarios in reservoir property evolution. In the synthetic case, a sequence of a diagenesis event and geological deformation are considered. The left column means the reservoir experienced diagenesis, and then deformation was applied. Since the deformation was applied after the rock became stiffer, the deformation is assumed to be accommodated by a brittle manner – by generating fractures.
As we simplified the deformation history of the reservoir, we made a simple scenario of how the reservoir properties had evolved. Simplified geological events which impact the reservoir properties are limited to diagenesis, deformation, and which occur first. For further simplicity, diagenesis is modeled as a 10% porosity reduction by cementation. Figure 4 depicts two geological scenarios of how the reservoir properties have evolved.

For the “fracturing” scenario, the true porosity in the depositional domain will be reduced by 10%. Elastic properties of the cemented rock are calculated by a rock physical model. In this example, we use the constant cement model (Avseth et al., 2000). Since we already have the principal strain components – their magnitudes and directions – from the deformation analysis, we can calculate stress components using Hooke’s law, by using point by point elastic modulus from a constant cement model. We assume that the synthetic reservoir may have only open mode fractures. Fracture intensity is scaled from principal stress where it is tensile. Fracture normal direction is decided by the most tensile principal strain direction.

For the “grain rearrangement” scenario, the true porosity is changed proportionally by the dilatation from the deformation. Fractional changes on a volume of interest need to be accommodated by pore volume changes, as depicted in Figure 5. This can be expressed as Equation 5.

\[
\phi_{\text{deformed}} = \frac{\phi_{\text{undeformed}} + \text{dilatation}}{1 + \text{dilatation}}
\]  

(5)

After the porosity is updated by the dilatation, a uniform 10% reduction by adding cement is applied as a diagenesis event. In this scenario, there is no fracture generation. For matrix permeability, the Kozeny-Carman relation was used (Mavko et al., 2003). Thus, we assume the
matrix permeability is a function of matrix porosity. For the synthetic reservoir, we choose the “fracturing” scenario as the true scenario. Thus, we believe the true reservoir is a naturally fractured reservoir.

Figure 6: Reservoir property evolution of the true case. Syn-depositional porosity is populated by unconditional SGSim. As diagenesis occurred, porosity reduction was applied. As deformation took place, fractures were generated by following fracture intensity from principal stress and fracture normals, from the most tensile principal strain direction. An explicit discrete fracture network was only populated in the initial production area. Flow related reservoir properties are modeled as a single medium with a summation of matrix and fracture properties, since the matrix permeability is relatively high compared to the fracture permeability.

Figure 6 depicts how the true reservoir properties are generated for the synthetic reservoir.
Porosity at the syn-deposition condition was cemented first. Then, the reservoir had been deformed under deformation scenario A. While it deformed, open mode fractures were populated by following the most tensile direction as the normal direction of fracture surfaces with the fracture intensity, which is scaled proportionally to the tensile stress induced from deformation. Since we are going to run a flow simulation only on the development area, actual DFN realizations are populated only within the production area.

**Generating Realizations in Different Geological Scenarios**

Now we can apply and test the proposed geomodeling workflow with the synthetic reservoir we have created. Let assume that we do not know the actual geological history of the reservoir, but that the true history is within our scenario.

<table>
<thead>
<tr>
<th>Ref.</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>S1</strong></td>
<td>Cemented $\rightarrow$ Flexural deformation</td>
</tr>
<tr>
<td><strong>S2</strong></td>
<td>Flexural deformation $\rightarrow$ Cemented</td>
</tr>
<tr>
<td><strong>S3</strong></td>
<td>Cemented $\rightarrow$ Minimal deformation</td>
</tr>
<tr>
<td><strong>S4</strong></td>
<td>Minimal deformation $\rightarrow$ Cemented</td>
</tr>
<tr>
<td><strong>Cv</strong></td>
<td>Conventional (no considerations)</td>
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*Figure 7: Multiple scenarios of structural deformation and reservoir property evolution. 2 interpretations on deformation and 2 interpretations of timing of cementation give 4 different scenarios. By including the conventional approach as one scenario, we need to test 5 different scenarios.*

Figure 7 compares all the scenarios by combining alternatives in our understanding of the mode of deformation and the mode of rock accommodation. Scenario S1 is the case when we chose the correction deformation interpretation and the timing of cementation. S1 and S3 will generate fractured reservoirs, while S2 and S4 generate reservoirs without fractures. Again, we are assuming that we have not seen any fractures from the vertical wells. “Cv” is a conventional geomodeling case, in which we implicitly assume that the reservoir properties remain identical from one state to another. Color codes in Figure 7 will be used in the same order on the following plots of reservoir responses.
Figure 8 compares the conventional workflow and the proposed workflow under scenario S2, to conduct an SGSim using porosity along the wells. For both cases, porosity along the wells in the current condition is identical. The conventional approach conducts a geostatistical simulation – a conditional SGSim in this case – using the observed porosity. The proposed workflow uses “restored” porosity under the geological assumptions. Since scenario S2 assumed the right deformation with the wrong sequence order of cementation events, the restored values will deviate from the true porosity along the well location in a syn-depositional condition. Both
cases honor the hard data along the well in current condition. But they are conducting any geostatistical simulations in the syn-depositional domain with different values, restored by different paths.

For the fractured case, i.e. scenarios S1 and S3, fracture intensity is slightly different for each realization, since the elastic modulus for each realizations are different by the populated porosity differences. Using the fracture intensity, one DFN simulation is conducted for individual realizations within the production area. Thus, each realization has a different fracture permeability & fracture porosity.

Across the five scenarios, 20 realizations are simulated. Thus, we have 100 realizations with 1 true model.
### Reservoir Responses from Different Assumptions on Geological History

**Figure 9**: One realization and its reservoir responses, out of 20 realizations from each scenario. The circles are the locations of exploratory vertical wells. Blue circles are converted to injectors. Porosity along these locations is used as hard data for geostatistical simulations. Top row - Ref. means true case. S1-S4 and Cv correspond to each scenario, including the conventional approach. Colors correspond to Figure 6. 1st column – matrix porosity, 2nd - Fracture intensity, 3rd - fracture permeability component on X axis, 4th - P-wave velocity distribution, 5th - oil saturation distribution after 900 days of production.

Figure 9 depicts one realization from each scenario, with the corresponding reservoir responses. Flow simulations are conducted using a Schlumberger eclipse. Rock physics models are used to calculate seismic velocity while considering porosity, saturation, mineralogy, cementation, and
fractures (Hudson, 1990; Mavko et al., 2003). Realizations from S2 and S4 do have all zero values on the fracture intensity maps, since S2 and S4 assume the deformation has been accommodated by the rocks via rearrangement of pore and matrix structures. The third column is the permeability tensor component on the X axis. The S2, S4, and Cv cases have different permeability tensor components for vertical direction, since they assume no fractures. Reference, S1, and S3 have different tensor components for each direction.

Figure 10: Flow responses of all realizations from different scenarios in the proposed and conventional workflows. Left – Cumulative oil production, Right – Cumulative water production.

Figure 10 plots the cumulative oil and water production of true reservoir responses and 100 realizations from different geological assumptions. As can be seen from the band of responses in each scenario, results from different geological assumptions are grouped together. Realizations from S1 and S3, which assume a fractured reservoir, show responses closer to the true responses than do the cases that do not assume a fractured reservoir. Specifically, S1, which shares a deformation history with the true case, produces bands of responses which scatter around the true oil production. If we examine the water production, the effect of using the proposed workflow with a good geological assumption becomes more noticeable. Except for realizations from S1 and S3, none of the 60 realizations from S2, S4, and Cv, achieve close forecasting of water production. The difference between oil and water production can be induced from the fact that the reservoir was initially oil filled. So, in any case, the initial status of production will have enough influx of oil. But the water breakthrough is hugely influenced by permeability distribution. It is worth noting that realizations from conventional approaches are far from the true cases.

In reality, we cannot have access to the true flow responses until we drain the field. Even though the proposed workflow gives better production forecasts, it would be less interesting
unless we can see which scenario is more suitable at an early stage. We may choose a more suitable scenario over a less suitable one if seismic attributes are also grouped by different scenarios.

Figure 11 shows the MDS plots of porosity, acoustic impedance, oil production, and water cut. As can be seen from the different MDS plots, different geological scenarios result in noticeable segregations of reservoir realizations. In real field cases, it is very unlikely to know the exact true porosity distribution. Thus, we may not have the ability to plot the red point on the MDS plot in real field applications. The bottom two plots are total oil production and water cut. The responses of realizations from different assumptions are well grouped, and S1 gives the best match with the true responses. Though the results from S3 show very close distribution on oil production, S1 distinguished itself when plotted by water-cut. Even with similar oil production,
which may impact revenue, giving a better prediction of water-cut, which is related to cost, would be important for reservoir evaluation. Unlike porosity, we can locate the true responses in real field cases. But we would need to wait until we actually develop and produce the area. Finally, the seismic attribute of initial saturation is accessible from an early stage, and we also have access to the true responses.

Discussion

100 realizations from four different geological scenarios of structural deformation in reservoir and reservoir property evolution were compared with true responses from a synthetic reservoir. Flow responses of the realizations using the correct scenario give good forecasts and uncertainty quantifications of flow responses. Realizations are grouped separately in an MDS plot, and the correct scenario gives closer segregation on the MDS plot when acoustic impedance is used.

If we do a thought experiment and assume the strain distribution from the deformation is uniform across the reservoir, and that any property evolution is also uniform around the reservoir, the proposed workflow becomes identical with the conventional workflow. For the case when any major geological event impacts an area uniformly, or with minor variation over the area of interest, the advantages of the proposed workflow may be less noticeable. But for cases where the effects of geological events vary spatially or are uncertain, the proposed workflow may become effective. For instance, in many cases, we know whether the reservoir is naturally fractured or not. But there are many cases where we failed to see any significant evidence of fractures, not only from seismic responses, but also from the vertical exploratory wells. In S3 in Figure 9, for instance, even though the realization has fractures, the low matrix porosity on the fractured area compensates for the seismic velocity drop by the existence of fractures. This may present difficulties in distinguishing fracture swarms. The realization on S4, a case with no fractures, gives the opposite example. Localized high porosity returns low seismic velocity, so one may want to consider the possibility of having fractures on that area. The virtue of the proposed workflow is being able to test the scenario at an early stage of the project cycle. And if it does not produce any significant differences from the conventional one, we can always use the conventional process. In that case, we may conclude that the area of interest may share a more or less homogenous geological history and impacts.

Summary and Future Work

In this report, we compared the effect of geological uncertainty on structural deformation of reservoir and reservoir property evolution in reservoir responses. Realizations of the reservoir
from different geological scenarios generate distinctively different reservoir responses when applied to a synthetic reservoir. Realizations from the correct scenario give closer reservoir responses with the true reservoir, not only in the flow responses but also in the seismic attributes on an MDS plot. This approach is very promising because we can test our geological understanding at the early stage of the project cycle. For the given synthetic case, the conventional workflow fails to generate realizations that produce similar reservoir responses. Application to a real field case should be conducted as a future study.

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