Uncertainties in rock properties and effects on seismic history matching

Amit Suman and Tapan Mukerji

ABSTRACT

Seismic history matching involves the use of time-lapse seismic data to match and predict the flow behavior of the reservoir. The changes in seismic velocities are attributed to changes in saturation and pore pressure, and these velocity changes can be modeled using Gassmann’s equations. In this paper, we explore how uncertainties in mechanical rock properties, specifically rock compressibilities, can affect the changes in seismic velocities. Reservoir rocks are described by at least four inter-related compressibilities, one of which affects the flow while the other impacts the wave velocities. Using the Stanford VI synthetic reservoir we show how uncertainties in pore compressibilities can lead to uncertainties in the time-lapse seismic response.

1. Introduction

Seismic time-lapse data has begun to play an important role in reservoir history matching. Time-lapse 3D seismic data can provide information on the dynamics of fluids in the reservoir based on the relation between variations of seismic signals and movement of hydrocarbons or/and changes in formation pressure. The calibrated reservoir models, optimally constrained to both integrated flow response and spatially distributed seismic responses, will give a better description of the reservoir, and consequently, more reliable forecasts.

The Reservoir characterization is based on building and updating a reservoir model by the integration of all data available during the different stages of reservoir development. At first initial static 3D model is built by the integration of seismic data, core and log measurements, sedimentary models and acoustic data, well tests and using proper geostatistical techniques. This model is used to set up a dynamic model of the reservoir, which allows us to evaluate different possible production scenarios. History matched models are required during the production life of the reservoir to improve forecast reliability. 4-D seismic data i.e. Time lapsed 3-D seismic data acquired along production can be used to monitor fluid property changes in the whole reservoir after specific processing. This new information can be used in the history matching process. Huang et al., (1997, 1998) formulated the simultaneous matching of production and seismic data
as an optimization problem, with updating of model parameters such as porosity. Walker and Lane (2007) presented a case study that included time-lapse seismic data as a part of the production history matching process, and show how the use of seismic monitoring can improve reservoir prediction. A typical step in seismic history matching is to compute the effects of changes in saturation and pore pressure on the seismic velocities. Parameters that are updated during history matching include porosity, permeability, and lithology or facies. One of the rock parameters that is often taken to be constant is the rock compressibility with respect to pore pressure. The rock compressibility affects both the flow, and the seismic wave velocities. This paper explores the sensitivity of flow response and seismic velocity changes to variations in rock compressibility. What might be some of the pitfalls in time-lapse modeling that might result from ignoring uncertainty in pore compressibility? In the next section, we define the various compressibilities used to describe porous media, and how they are related to each other. We then present examples of sensitivity analyses using flow simulation and velocity modeling based on the Stanford VI synthetic dataset (Castro et al., 2005).

2. Rock and pore compressibility

A nonporous elastic solid has a single compressibility

$$\beta = \frac{1}{V} \left( \frac{\partial V}{\partial \sigma} \right)$$

where $\sigma$ is the hydrostatic stress applied on the outer surface and $V$ is the sample bulk volume. In contrast, compressibilities for porous media are more complicated. We have to account for at least two pressures (the external confining pressure, $\sigma_c$ and the internal pore pressure, $\sigma_p$) and two volumes (bulk volume, $V_b$ and pore volume, $V_p$). Therefore, we can define at least four compressibilities. Following Zimmerman’s (1991) notation, in which the first subscript indicates the volume change (b for bulk, p for pore) and the second subscript denotes the pressure that is varied (c for confining, p for pore), these compressibilities are

$$C_{bc} = \frac{1}{V_b} \left( \frac{\partial V_b}{\partial \sigma_c} \right) \sigma_p$$
Note that the signs are chosen to ensure that the compressibilities are positive when tensional stress is taken to be positive. Thus, for instance, \( C_{bp} \) is to be interpreted as the fractional change in the bulk volume with respect to change in the pore pressure while the confining pressure is held constant. These are the dry or drained bulk and pore compressibilities. The effective dry bulk modulus is \( K_{dry} = 1/C_{bc} \), and is related to the seismic P-wave velocity by 

\[
V_p = \sqrt{\frac{K_{dry} + 4\mu/3}{\rho}}
\]

where \( \rho \) is the dry bulk density. Dry rock velocities can be related to the saturated bulk rock velocity through the Gassmann equations. The different compressibilities can be related to each other by elasticity theory using linear superposition and reciprocity. The compressibility \( C_{pp} \) appears in the fluid flow equations through the storage term, and can be related to \( C_{bc} \) (and hence to seismic velocity) by the equation

\[
C_{pp} = \frac{1}{\rho} \left[ \frac{C_{bc} - (1+\phi)K_0}{\phi} \right]
\]

where \( \phi \) is the porosity and \( K_0 \) is the solid mineral bulk modulus.

In time-lapse reservoir modeling the reservoir is often described by a heterogeneous and variable porosity and the seismic velocity is related to variations in saturations and pore pressure.
However, the related variability in $C_{pp}$ is not taken into account. How do variations in this pore compressibility affect the changes in modeled seismic velocities? What might be some of the pitfalls in time-lapse modeling that might result from ignoring uncertainty in $C_{pp}$? These are the motivating questions that we have begun to address.

3. **Examples using Stanford VI reservoir**

Stanford VI (Castro et al., 2005) is an exhaustive 3-D reference data set that exhibits a smooth top and bottom surface representing a trap in the form of anticline. Specifically, it is an asymmetric anticline with axis N15°E. The anticline has a different dip on each flank and generally the dip decreases slowly towards the northern part of the structure. The maximum dip of the structure is 8°. The reservoir is 3.75 Km wide (East-West) and 5.0 Km long (North-South), with a shallowest top depth of 2.5 Km and deepest top depth of 2.7Km. The reservoir is 200m thick and consists of three layers with thicknesses of 80 m, 40 m and 80 m respectively. The reservoir model is represented in a 3D regular grid of 6 million cells (150x200x200), with realistic dimensions for current day models (25m in the X and Y directions and 1m in the Z direction). For this study the above reservoir model is upscaled such that new upscaled model approximately preserves the local heterogeneities. The model used for this study has 0.75 million cells (75x100x100) with appropriate dimension (50m in X and Y direction and 2m in Z direction). The stratigraphic model corresponds to a fluvial channel system, and the petrophysical properties computed for this reference reservoir correspond to the classical porosity, density, permeability and Seismic P-wave and S-wave velocities. The reservoir model exhibits a complete set of physical seismic attributes, which are computed from well-known rock physics expressions and subsequently filtered and smoothed to obtain realistically looking as would have been obtained from actual seismic acquisition and modeling.

**Flow Simulation**

To generate the 3D seismic data sets ($V_p$ and $V_s$) at different times during oil production, we performed a flow simulation where water and oil are the only fluids present in the reservoir. Flow simulation provided us the distribution of fluids and variation of pore pressure in the reservoir at any particular time and place after the start of production. In order to use Gassmann’s equations
correctly we need the saturations of each fluid at every point in space. We have used an isothermal black-oil model since there are only two phases in the reservoir (oil and water) and we only inject water at a certain time during the flow simulation. 30 years of oil production have been simulated with an active aquifer below the reservoir and water injector wells that become active after the aquifer water influx fails to maintain the pressure. Flow simulation is performed for two different pore compressibilities ($C_{pp}$), $1e-5$ psi$^{-1}$ and $1e-6$ psi$^{-1}$.

The oil and water PVT properties used for the flow simulation are summarized in the following table. The relative permeability curves are kept constant for the entire reservoir, and no capillary pressure is considered in the flow simulation ($P_c = 0$).

<table>
<thead>
<tr>
<th>Property</th>
<th>Oil</th>
<th>Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density ($lb/ft^3$)</td>
<td>45.09</td>
<td>61.80</td>
</tr>
<tr>
<td>Viscosity (cp)</td>
<td>1.18</td>
<td>0.325</td>
</tr>
<tr>
<td>Formation Volume Factor</td>
<td>0.98</td>
<td>1.0</td>
</tr>
</tbody>
</table>

An active constant flux aquifer is below the reservoir and the water-oil contact is at 9, 840ft depth. The constant water inflow rate is of 31, 000STB/day. The flow simulation starts in January of 1975 with six wells in production (primary production). A summary of production schedule is shown in Table 1. The reservoir has 30 years of active production with 31 oil producer wells and 15 water injector wells. As indicated in the production schedule table, not all wells start producing oil or injecting water at the same time, as is typical of an actual reservoir development where new wells are constantly added. Producer wells are controlled by constant liquid rate production with a BHP constraint of 2700psia, while injector wells are controlled by constant water injection rate. While oil production takes place, the water-oil contact starts to rise and the producer wells located far away from the structure axis start producing both oil and water. For those producer wells, P21 through P28, an economic limit is set such that they are converted to water injectors after they reach water cut higher than 0.5.

4. **Effect of Saturation**

Flow simulation provides us with the variation of saturation of fluids in the reservoir after the startup of production. As previously stated, seismic velocities are function of saturations of the
different fluids in the reservoir. The distribution of fluid saturations in the reservoir is obtained for two different pore compressibilities (1e-6 psi-1 and 1e-5 psi-1). These variations of saturations are responsible for change in the total density and finally changes in the seismic velocities as shown below. 3-D time-lapse seismic velocities are generated using seismic velocities, density and Gassmann’s fluid substitution as described below.

The theoretical constant cement model (Avseth et al., 2005) predicts the bulk modulus $K$ and shear modulus $G$ of dry sand with constant amount of cement deposited at grain surface. Seismic P-wave and S-wave velocities are functions of density and two elastic moduli, the bulk modulus $K$ and the shear modulus $G$.

\[
V_p^2 = \frac{K + \frac{4}{3}G}{\rho}
\]

\[
V_s^2 = \frac{G}{\rho}
\]

Gassmann’s equation shown below is used to obtain the bulk modulus $K_2$ of the rock saturated with fluid 2, which is mixture of oil and water in this case.

\[
\frac{K_2}{K_{min} - K_2} - \frac{K_{fl2}}{\phi(K_{min} - K_{fl2})} = \frac{K_1}{K_{min} - K_1} - \frac{K_{fl1}}{\phi(K_{min} - K_{fl1})}
\]

$K_1$ and $K_2$ are the rock’s bulk moduli with fluids 1 and 2 respectively, $K_{fl1}$ and $K_{fl2}$ are the bulk moduli of fluids 1 and 2, $\phi$ is the rock’s porosity, and $K_{min}$ is the bulk modulus of the mineral. The shear modulus $G_2$ remains unchanged $G_2 = G_1$ at low frequencies appropriate for surface seismic data, since shear stress cannot be applied to fluids. The fluid bulk moduli are a function of the oil composition, pore pressure and temperature. The fluid moduli and densities are obtained from the usual Batzle-Wang (1992) relations. The density of the rock is also transformed and the density of the rock with the second fluid is computed as:
\[ \rho_2 = \rho_1 + \phi (\rho_{f2} - \rho_{f1}) \]

Having transformed the elastic moduli and the density, the compressional and shear wave velocities of the rock with the second fluid are computed as

\[ V_p = \sqrt{\frac{K_2 + \frac{4}{3} G_2}{\rho_2}} \]

\[ V_s = \sqrt{\frac{G_2}{\rho_2}} \]

5. **Effect of Pore pressure and Saturation:**

Seismic velocities are affected by the pore pressure as well as the fluid saturations. Flow simulation provides us the variation of pore pressure and saturations with respect to time after the startup of the production. Using a proper pore pressure model seismic velocities of dry rock are first corrected for changes in pore pressure. Now corrected seismic velocities of dry rocks are used to calculate the seismic velocities by fluid substitution using Gassmann’s equation as stated above. The pore pressure effect on the dry rock frame in modeled using an exponential relation, based on an empirical relation derived from dry core data for Gulf of Mexico sandstones (Avseth et al., 2005).

6. **Results and future work**

All of the figures below show \( V_p \) at different times at different cross section of a Cartesian grid. The results are shown on a Cartesian grid having the same I, J, and K as that of reservoir model. Figure 1 shows the \( V_p \) at the initial condition of the reservoir. Figures 2, 3 and 4 show the percentage change in \( V_p \) after 10, 20 and 30 year of production respectively. These results only consider the changes in saturation with respect to time. So far we have not considered the effect of change of pore pressure on the dry rock frame.
We observed no significant variations in the saturation distribution for two different compressibilities. As a result, there is no significant variation in the seismic wave velocities for
two different values of pore compressibilities. Maximum percentage change in $V_p$ is around 6% - 7% and it is almost the same for both the compressibilities.

Our next step is to consider the effect of change of saturation as well as changes in pore pressure on seismic velocities, since the effect of uncertainty in $C_{PP}$ impacts mostly the pore pressure distributions. Figures 5 to 10 show $V_p$ for two different pore compressibility after 10, 20 and 30 year of production. Figures 11 to 16 show percentage change in $V_p$ after 10, 20 and 30 year of production.

**Fig 5:** $V_p$ After ten years (1e-5 psi$^{-1}$)  
**Fig 6:** $V_p$ After ten years (1e-6 psi$^{-1}$)  
**Fig 7:** $V_p$ After twenty years (1e-5 psi$^{-1}$)  
**Fig 8:** $V_p$ After twenty years (1e-6 psi$^{-1}$)
Fig 9: $V_p$ After thirty years (1e-5 psi$^{-1}$)

Fig 10: $V_p$ After thirty years (1e-6 psi$^{-1}$)

Fig 11: % Change in $V_p$ after 10 years (1e-5 psi$^{-1}$)  Fig 12: % Change in $V_p$ after 10 years (1e-6 psi$^{-1}$)

Fig 13: % Change in $V_p$ after 20 years (1e-5 psi$^{-1}$)  Fig 14: % Change in $V_p$ after 20 years (1e-6 psi$^{-1}$)
Fig 15: % Change in $V_p$ after 30 years ($10^{-5}$ psi$^{-1}$)    Fig 16: % Change in $V_p$ after 30 years ($10^{-6}$ psi$^{-1}$)

We observe a significant increase in % change of $V_p$. The maximum % change in $V_p$ after 10 years due to saturation change is 6%-7%. Now when we consider the effect of change of pore pressure the maximum % change in $V_p$ is 17%-18% after 10 year of production for pore compressibility of $10^{-5}$ psi$^{-1}$. For pore compressibility of $10^{-6}$ the maximum % change in $V_p$ after 10 year of production is 24%-25%. Therefore, for two different pore compressibilities the difference in maximum % change in $V_p$ is around 6%-7%. In addition, the differences are significant as compared to the previous case where only saturation effects were considered. These observations indicate that changes in seismic velocities can depend upon pore compressibility and thus uncertainties attached to pore compressibilities can not be ignored. There is an increase in % change in $V_p$ after 20 years and 30 year of production but it is very similar for both the pore compressibilities. This is because injectors come into play maintaining the pore pressure. Thus, changes in pore pressure and pore compressibility play an important role in time-lapse modeling and hence in seismic history matching. These are very preliminary observations and further analysis on the variation of pore compressibilities, and their relation to different lithologies are needed. The effect of different rock compressibility on seismic history matching is an important issue and should be studied in detail.

References


## Table: 1

<table>
<thead>
<tr>
<th>Date</th>
<th>Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>January 1975</td>
<td>Start primary oil production with wells P1 to P6.</td>
</tr>
<tr>
<td>January 1979</td>
<td>Wells P22 and P24 are open to production.</td>
</tr>
<tr>
<td>January 1981</td>
<td>Wells P26, P28 and P30 are open to production.</td>
</tr>
<tr>
<td>January 1983</td>
<td>Wells P21, P23, P25, P27, P29 and P31 are open to production.</td>
</tr>
<tr>
<td>January 1986</td>
<td>Wells P7, P9, P11, P13, P15, P17 and P19 are open to production. Start water injection in wells I32, I33, I34, I36, I37, I38, I41, I43 and I45.</td>
</tr>
<tr>
<td>October 1989</td>
<td>Start water injection in wells I44, I46.</td>
</tr>
<tr>
<td>January 1995</td>
<td>Increasing production rate of wells P1 to P6.</td>
</tr>
<tr>
<td></td>
<td>Increasing water injection rate of wells I36, I42, I43, I44, I45 and I46.</td>
</tr>
<tr>
<td>January 1998</td>
<td>Increasing production rate of wells P7 to P20.</td>
</tr>
<tr>
<td>January 2001</td>
<td>Increasing production rate of wells P1 to P6.</td>
</tr>
<tr>
<td>March 2005</td>
<td>End of the flow simulation.</td>
</tr>
</tbody>
</table>