Downscaling saturations for modeling 4D seismic data

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Abstract

4D seismic data is used to monitor the movement of fluids in the reservoir with time and could be incorporated into the process of history matching.

Traditional history matching of production data perturb the reservoir model until the production history (computed by running a flow simulator) matches the observed in the field. Similarly, in order to match 4D seismic we aim to minimize the difference between the 4D seismic observed in the field and the 4D seismic computed from the model.

Modeling 4D seismic data involves the computation of two 3D seismic data sets: the “Base 3D seismic data”, and the “Time lapse 3D seismic data”. Modeling the “Base 3D seismic data” represents no problem since it is assumed that the reservoir has a constant initial distribution of fluids. However, modeling the “Time Lapse seismic data” involves using the coarse scale distribution of fluids from the reservoir simulator.

It has been observed that fine details in the saturation distribution (although below seismic resolution) can impact the seismic response (Mavko and Mukerji, 1998; Sengupta and Mavko, 1998; Sengupta, 2000). Downscaling saturation outputs from the flow simulator to a more realistic distribution is required to provide a good quantitative match with 4D seismic data.

In this paper we propose a method for downscaling saturations where a local fine scale flow simulation is performed to reconstruct the fine scale saturation using local boundary conditions determined from global coarse scale two-phase flow solutions, and show how this procedure fits in the overall workflow of matching 4D seismic data.
1 Introduction

The dependence of seismic velocities and impedance on pore fluids has been observed in both laboratory and field measurements (Nur and Simmons, 1969; Wang and Nur, 1988). The fluid contained in the pore space changes the overall elastic moduli of the rock and therefore changes the seismic velocities. Intuitively, the less compressible the fluid in the pore space the more resistant to wave-induced deformations the rock is. A rock with a less compressible fluid (such as brine) is stiffer than a rock with a more compressible fluid (such as gas). This fundamental observation is the basis for using 4D seismic data in predicting fluid saturation changes in the reservoir.

Termed “four-dimensional seismology” (Nur, 1989), 4D seismic data is referred to the set (usually two) of three-dimensional seismic data acquired at different times over the same area, to assess the changes in a producing hydrocarbon reservoir with time. The changes can be observed in fluid location, saturation, pressure and temperature; therefore the main application of 4D seismic is to monitor fluid flow in the reservoir.

Typically, the difference between the two 3D seismic datasets recorded at different times is an indicator of the areas in the reservoir where the distribution of fluids has changed. With such a close relationship between 4D seismic and production “dynamic” data, incorporating 4D seismic data into the history matching workflow seems inevitable, and the final reservoir model we perturb during history matching should reproduce both production data and 4D seismic.

Traditional history matching of production data perturb the reservoir model until the production history from such model matched the observed in the field; the production history from the model is computed by running a flow simulator. Similarly, in order to match 4D seismic we aim to minimize the difference between the 4D seismic observed in the field and the computed from the model.

Contrary to common approaches used in the practice of history matching that perturb the upscaled reservoir model, we use the alternative procedure of perturbing the high resolution geocellular model which has been proposed by Caers (2003) and used for integrating “dynamic” and “static” data with successful results (Caers, 2003; Hoffman and Caers, 2003; Kim and Caers, 2003).
The high resolution geocellular model is often generated with geostatistical techniques, consisting of millions of grid cells that practically cannot be managed by actual flow simulators. To make flow simulation feasible, the number of grid cells needs to be reduced, hence this high resolution model is upscaled to a manageable grid block scale. To achieve a history match, Tureyen and Caers (2003) proposed to perturb the high resolution model based on the flow response obtained on the coarsened flow simulator model. Using their approach, one obtains a flow simulation model that not only matches production but also honors any other data, such as well-logs, seismic and geologic information.

In Castro and Caers (2004), following the approach of Tureyen and Caers (2003), the simulated 4D seismic response is modeled for the high resolution geocellular model using the distribution of fluids given by the flow simulator, typically water saturation. The scale difference between the 4D seismic and flow simulation response (saturation) can be up to two orders in magnitude. This raises the question of how to input the coarse scale saturations into the high resolution geocellular model.

Although a direct approach is to use the coarse scale saturation from the flow simulator and simply copy the coarse scale saturation to the high resolution model, it has been observed that the fine details in the saturation distribution (although below seismic resolution) can impact the seismic response (Mavko and Mukerji, 1998; Sengupta and Mavko, 1998; Sengupta, 2000). For this reason, the seismic forward model should be computed using the high resolution reservoir model instead of the coarse flow simulator model.

Important details such as “patches” of bypassed oil can affect the seismic signature, although sometimes seismic waves are not able to “resolve” those features (i.e. identify its boundaries) they can “detect” them, since they influence velocity and impedance. Coarse scale saturations from the flow simulator often show a very smooth version of those “patches” or simply do not show them at all due to the upscaling.

Downscaling saturation outputs from the flow simulator to a more realistic distribution is required to provide a good quantitative match with 4D seismic data, even though the fine details in the saturation distribution are below seismic resolution. Previous work has been done by Sengupta (2000) in downscaling saturations from the reservoir simulator by incorporating high spatial frequencies from well logs. However, their downscaling was performed
based only on static information, while it is clear that the distribution of saturations depends on the particular flow problem and process at hand. This paper addresses that issue and proposes a method for downscaling saturations where the local flow problem is solved consistently with the coarse flow solutions.

The paper starts with the detailed description of the modeling of 4D seismic data, continues with the proposed method for downscaling saturations, and ends by presenting a 2D synthetic example where the method has been successfully applied.
2 History matching and 4D seismic data

Traditionally, the workflow used for history matching consists of perturbing the upscaled reservoir model until production history is matched. The high resolution geocellular model is often generated with geostatistical techniques, consisting of millions of grid cells that practically cannot be managed by actual flow simulators. To make flow simulation feasible, the number of grid cells is reduced, this high resolution model is upscaled to a manageable grid block scale.

Perturbing upscaled properties imply degrading the fine scale model which honors both hard and seismic data. The final result of this traditional approach is a reservoir model that matches production history, but precludes the prediction of future production. An alternative approach, proposed by Tureyen and Caers (2003), achieves a history match by perturbing the high resolution model based on the flow response obtained on the coarsened flow simulator model. Using this workflow it is possible to obtain a final model that not only matches the production history but also honors important geological hard and seismic data, and provides accurate predictions of reservoir performance.

Production data is often termed “dynamic” data since it changes with time and reflects the fluid flow occurring in the reservoir. 4D seismic data could also be considered “dynamic” since it is used to monitor changes in the seismic data over time, due to the movement of fluids in the reservoir.

History matching both production and 4D seismic data is proposed by Castro and Caers (2004) using the workflow in Figure 1. Following the approach of Tureyen and Caers (2003), the simulated 4D seismic response is modeled for the high resolution geocellular model using the distribution of fluids given by the flow simulator.

4D seismic data is forward modeled using the high resolution reservoir model instead of the coarse flow simulator model, since it has been observed that the fine details in the saturation distribution (although below seismic resolution) can impact the seismic response (Mavko and Mukerji, 1998; Sengupta and Mavko, 1998; Sengupta, 2000).
Figure 1: Proposed workflow for incorporating 4D seismic data in the process of history matching. After Castro and Caers (2004).
3 Modeling 4D seismic data

4D seismic data is referred to several three-dimensional (3D) seismic data acquired at different times over the same area to assess changes in a producing hydrocarbon reservoir with time.

In order to create the 4D seismic response, two 3D seismic data sets are forward modeled: the first seismic data set (Base 3D seismic data) is created using the acoustic impedance of the reservoir prior to production, while the following seismic data set (Time lapse 3D seismic data) is created using the acoustic impedance of the reservoir as it has changed due to the movement of fluids in the reservoir (after flow simulation).

The acoustic impedance of the reservoir after flow simulation is obtained using a procedure termed fluid substitution which relies on a mathematical transformation introduced by Gassmann (1951). This transformation allows to calculate the elastic moduli of the rock as one fluid displaces another in the pore space:

\[
\frac{K_2}{K_{min} - K_2} - \frac{K_{fl2}}{\phi(K_{min} - K_{fl2})} = \frac{K_1}{K_{min} - K_1} - \frac{K_{fl1}}{\phi(K_{min} - K_{fl1})}
\] (1)

where \(K_1\) 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 rock frame.

Figure 2 shows how the “fluid substitution” procedure is followed in practice. The process starts with the compressional \(V_p\) and shear \(V_s\) wave velocities measured on rocks saturated with the initial pore fluid and then extracting the bulk and shear moduli:

\[
K_1 = \rho_1(V_p^2 - \frac{4}{3}V_s^2)
\]

\[
\mu_1 = \rho_1V_s^2
\] (2) (3)

The bulk modulus of the rock containing the second fluid \(K_2\) is computed using Gassmann’s relations (Eq. 1); however, the shear modulus \(\mu_2\) remains unchanged \(\mu_2 = \mu_1\) since shear stress cannot be applied to fluids. 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:

\[ V_p = \sqrt{\frac{K_2 + \frac{4}{3}\mu_2}{\rho_2}} \]  
\[ V_s = \sqrt{\frac{\mu_2}{\rho_2}} \]  

Figure 2: General procedure for fluid substitution.

The fluid contained in the rock could be a single fluid like brine or oil, however it can also be a mixture of fluids. The bulk modulus of each fluid is needed in order to perform Gassmann’s transformation; when dealing with single fluids, elastic moduli can be gathered from tables (Mavko, Mukerji, Dvorkin, 1998), however this is not the case for mixtures and partial saturations need to be considered.
The most common approach to modeling partial saturation (gas/water or oil/water) or mixed fluid saturations (gas/water/oil) is to replace the set of phases with a single “effective fluid”. The bulk modulus of this “effective fluid” is computed with a weighted harmonic average, termed Reuss average in the rock physics literature:

\[
\frac{1}{K_{fl}} = \sum_i S_i K_i
\]  

where \(K_{fl}\) is the effective bulk modulus of the fluid mixture, \(K_i\) denotes the bulk moduli of the individual fluid phases, and \(S_i\) represents their saturations. This model assumes that the fluid phases are mixed at the finest scale.

The density of the “effective fluid” is computed with the mixing formula:

\[
\rho_{fl} = \sum_i S_i \rho_i
\]  

where \(\rho_{fl}\) is the effective density of the fluid mixture, \(\rho_i\) denotes the density of the individual fluid phases, and \(S_i\) represents their saturations.

Modeling the “Base 3D seismic data” for the fine scale reservoir model represents no problem since it is assumed that the reservoir has a constant initial distribution of fluid. For example, the reservoir could be fully saturated with oil and the water saturation will be equal to the irreducible water saturation (\(S_w(u) = S_{wi}\)) at every grid cell of the high resolution model. If the reservoir has a gas cap or a water-oil contact, we usually have a good idea of the location of these features before production starts and use this information to model the acoustic impedance of the reservoir.

Modeling the “Time Lapse seismic data” for the fine scale reservoir model involves using the coarse scale \(S(v)\) from the reservoir simulator.

### 3.1 Fluid substitution on the high resolution model

One approach often used for performing the fluid substitution on the fine scale model consists of populating all high resolution grid cells within a coarse grid block with a single value: the coarse saturation for that particular coarse grid block (see Figure 3).
Figure 3: Traditional approach of resampling the coarse saturation by populating all high resolution grid cells within the coarse grid block with a single value: the coarse saturation for that particular coarse grid block.

The problem arises when fine details in saturation that are not captured by the coarse scale flow simulation have a strong impact on the seismic response. The modeled “Time Lapse seismic data” is not able to accurately predict the distribution of fluids since it has been modeled using a smooth or upscaled version of saturation.

The solution to this problem cannot rely on running the flow simulator on the high resolution model. It is unfeasible, in practice, to run a flow simulator using a reservoir model that often consists of millions of grid cells. Moreover, incorporating the modeling of 4D seismic into the process of history matching involves running tens or hundreds of flow simulations which requires to use a reservoir model with a more manageable grid block scale.

One approach to solve this problem consists of upscaling the acoustic impedance and performing fluid substitution by directly using the coarse scale $S(v)$ from the reservoir simulator, $v$ being the location a reservoir flow simulation grid block. However, when upscaling acoustic impedance we smooth the acoustic contrasts between layers in the geological model, and also create artificial contrasts due to the size of the coarse block.

Another approach is to downscale the coarse saturation obtained by the flow simulator. In this regard, previous work has been done by Sengupta (2000) in downscaling saturations from the reservoir simulator by incorpo-
rating high spatial frequencies from well logs.

Sengupta (2000), presented a reservoir monitoring case study of a reservoir that produces oil under water and gas injection. The downscaling is performed at the well location (Figures 4 and 5) by scaling and thresholding the flow simulator saturation profile according to the effective porosity and other well logs. Figure 4 shows that the simulator model of permeability, porosity, and initial fluid saturations are smoother than the same properties computed from well logs.

![Figure 4: Comparing well-log and simulator properties: the red curves correspond to the flow simulator, while the blue curves correspond to the well logs. Left to right: φ = porosity, k = permeability, \( S_w \) = water saturation, and \( S_g/o \) = simulator gas saturation and well log oil saturation. After Sengupta, 2000.](image)

In order to downscale the saturation from the simulator, Sengupta (2000) used the well log saturations. Figure 5 shows the original profile of the gas saturation (\( S_g \)) taken from the flow simulator, and five estimates of the downscaled \( S_g \), each representing a different downscaled model. These estimates are computed using the smooth \( S_g \) profile from the simulator and the initial
oil saturation \((1 - S_w)\) at the well location. Assuming gas is most likely to replace oil in the high porosity, high permeability sands, the five estimates of \(S_g\) presented in Figure 5 were created by Sengupta (2000) as follows:

- profile (b) is created by setting to zero the smooth flow simulator profile \(S_g\) in the zones of zero effective porosity,
- profile (c) is obtained by scaling profile (b) according to the high resolution \(S_o\) profile at the well, based on the assumption that gas is most likely to replace oil.
- profiles (d) to (f) are obtained by successive hierarchical thresholding of profile (c). Although it is not explicitly described, Sengupta mentions the thresholding can be based on various rock physics parameters such as porosity, \(V_{shale}\) or high resolution permeability.

![Figure 5: Downscaling saturations from the flow simulator: (a): \(S_g\) taken from the simulator, (b), (c), (d), (e), (f): Estimations of downscaled \(S_g\). After Sengupta, 2000.](image)

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Using each of the downscaled 1D saturation profiles, the synthetic time-lapse differential AVO attributes are computed for each profile (Figure 6), from the near offset ($5^\circ - 15^\circ$) and the mid offset ($15^\circ - 25^\circ$). The time-lapse differential corresponds to the percent change in root mean square (RMS) amplitude between the two seismic surveys.

Figure 6 shows a cross plot between the time-lapse differential for near offsets and mid offsets, where the color filled dots are values computed from the real seismic data and the empty circles correspond to the synthetic values obtained from the downscaled $S_g$ profiles shown in Figure 5. From this figure, Sengupta concluded that honoring the vertical heterogeneity observed at the well, decreases the mismatch between the real and synthetic seismic.

![Figure 6](image)

Figure 6: Cross plot of time-lapse differential AVO attributes from real data around the well, and from synthetics corresponding to smooth and downscaled saturation profiles. The error bars represent the uncertainty in synthetic seismic attributes due to the lack of information about spatial distribution and total amount of gas. *Modified from Sengupta, 2000.*

The results presented by Sengupta (2000) are very encouraging, however the downscaling method used is purely static, no dynamic considerations are
taken into account. The distribution of saturations in the reservoir depends on the particular flow problem: initial condition of the reservoir and flow boundary conditions.

A systematic and generalized process is needed for downscaling the coarse scale volume of saturations from the flow simulator that accounts for both static information and the particular flow problem. The method proposed in this paper performs a local fine scale flow simulation to reconstruct the fine scale saturation using local boundary conditions determined from global coarse scale two-phase flow solutions.
4 Downscaling saturations

To illustrate the methodology followed in this paper for downscaling coarse saturations from the reservoir flow simulator, we present a simple example, yet that effectively describes the importance of downscaling when modeling 4D seismic data.

Typically, reservoir models reflect a high level of geological heterogeneity which is not manageable for flow simulators, and upscaling techniques are often introduced to coarsen these geological models. The 2D geological model used for the example is shown in Figure 7, it represents a layered sand interval with different permeability values for each layer. Acoustic properties such as impedance \( Z = \rho V_p \) are assumed constant with the layer interval \( \rho = 2.3 g/cc \), and \( V_p = 2300 m/sec \).

Figure 7: Fine scale permeability model (isotropic) for a layered reservoir. The axis correspond to the grid block number.

Many upscaling techniques exists; however, the ultimate goal is that under the same boundary conditions the coarsened flow model replicates the fine scale flow in terms of key parameters such as flow rate. Usually, these techniques are referred to as flow-based upscaling techniques, and we use an upscaling procedure of this kind (Deutsch, 1989). In this work, the fine scale
permeability is isotropic and since the simulation grid follows the reservoir layering, we obtain two effective permeabilities \(k_x\) and \(k_z\) per coarse grid block after the upscaling, shown in Figure 8.

![Figure 8: Coarse scale effective permeability model (anisotropic) for the layered reservoir: \(k_x\) (left) and \(k_z\) (right). The axis correspond to the grid block number.](image)

Using these effective permeabilities, we run the flow simulator considering a water injector well at the left boundary of the reservoir and an oil producer at the right boundary. The injection rate is set as 400 $STB/day$, the production rate is set as 415 $STB/day$, and 200 days of oil production are simulated. The resulting water saturation in the reservoir at the end of the simulation is shown in Figure 9.

The idea is now to downscale this saturation map to the fine scale to capture small details of the water front and to reduce the smooth character of the coarse saturation map. The downscaling procedure we propose simulates the local flow at every coarse grid block using the sub-grid fine scale permeability and local boundary conditions that are consistent with flow at the coarse scale.
4.1 Governing equations

In Reservoir simulation, a numerical solution of the partial differential equations (PDEs) that describe the flow of fluids in petroleum reservoirs is simulated. The discrete equations can be developed by writing mass balance directly over the grid blocks or by developing the general PDEs and then discretizing them according to the particular coordinate system.

Considering Darcy’s law for two-phase oil-water flow:

\[
\vec{u}_w = \frac{k k_{rw}}{\mu_w} \nabla (p_w + \rho_w g z) \tag{9}
\]

\[
\vec{u}_o = \frac{k k_{ro}}{\mu_o} \nabla (p_o + \rho_o g z) \tag{10}
\]

where \( p \) is pressure, \( \vec{u} \) is the Darcy velocity, \( k \) is permeability, \( \mu_w \) and \( \mu_o \) are the viscosities of water and oil, \( \rho_w \) and \( \rho_o \) are the densities of water and oil,
$k_{rw}$ and $k_{ro}$ are the relative permeabilities of water and oil respectively.

Using the equations above and considering mass conservation on a control volume (or grid block) for each phase, i.e. rate of change of mass in the volume equals the net influx of mass, we are able to obtain two equations that describe the two phase oil-water flow:

$$\phi \frac{\partial S_w}{\partial t} + \nabla \cdot (\vec{u}_w) = 0 \quad (11)$$

$$\nabla \cdot (\lambda_T \nabla p_o) = 0 \quad (12)$$

$S_w$ corresponds to the saturation of the displacing fluid (water), $t$ is time, and $\lambda_T$ is the total mobility ($\lambda_T = \lambda_w + \lambda_o$, $\lambda_w = \frac{k_{rw}}{\mu_w}$, $\lambda_o = \frac{k_{ro}}{\mu_o}$).

These equations assume zero gravitational and capillary forces, and they are termed “saturation equation” and “pressure equation” respectively. In reservoir simulation, these two equations are solved using finite differences. In this work we use a sequential procedure (IMPES) that solves the “pressure equation” first (implicitly) and then the “saturation equation” (explicitly).

4.1.1 Fine and coarse scale flow

In order to downscale the coarse-scale saturation map to the fine scale we simulate the local flow at every coarse grid block using the sub-grid fine scale permeability and local boundary conditions that are consistent with flow at the coarse scale.

Coarse scale flow is performed using a commercial flow simulator, which in this case corresponds to ECLIPSE, and the following variables are obtained for each coarse grid block $v$ of the the coarse grid: water saturation $S_{w}^{\text{coarse}}(v)$, total flux in the $x$ direction $q_x(v)$ and total flux in the $z$ direction $q_z(v)$.

Using this information, for each coarse grid block $v$ the fine scale flow is simulated locally for the sub-grid of $n_x \times n_z$ fine grid blocks $u$ (Fig. 10) by solving the flow equations described earlier. For this simulation, the sub-grid
fine scale permeability is used, and local boundary conditions are imposed according to the coarse grid block variables we obtained from the coarse-scale flow simulation.

Boundary conditions for solving the “pressure equation” correspond to the fluxes at each of the faces of the grid block, while the boundary conditions for solving the “saturation equation” correspond to the saturation value at the inlet faces. The initial condition corresponds to $S_w^{fine}(u) = 0.0$ for every fine grid block.

![Diagram of flow domains: coarse scale flow, and local fine scale flow.](image)

For a particular coarse block, flux boundary conditions are computed for all fine sub-grid boundaries of the coarse block. Following the work of Chen et al. (2003), the boundary fine scale fluxes are computed proportional to the fine grid inter-block transmissibility. For example, for a given coarse block of size $n_x \times n_z$ (Figure 10) the local fine scale flux boundary conditions are computed for the boundaries $x = 0$, and $z = 0$ as follows:

$$ (q_x)_{0,j} = \frac{(T_x)^{1/2,j}}{\sum_{j=1}^{n_z}(T_x)^{1/2,j}} q_x^c \quad j = 1, \ldots, n_z $$

(13)

$$ (q_z)_{i,0} = \frac{(T_z)^{i,1/2}}{\sum_{i=1}^{n_x}(T_z)^{i,1/2}} q_z^c \quad i = 1, \ldots, n_x $$

(14)
where \( q_x^c \) and \( q_z^c \) are the coarse fluxes in the \( x \) and \( z \) direction obtained from the coarse flow simulation, \( T_x \) and \( T_z \) are the fine scale inter-block transmissibilities in the \( x \) and \( z \) direction. According to Chen et al. (2003), this reconstruction guarantees flux continuity across fine scale cells in neighboring coarse blocks and accounts for sub-grid heterogeneity, in addition to forcing the sum of the fine grid fluxes to be equal to the corresponding coarse grid flux.

Additionally, saturation boundary conditions are established for the fine grid inlet boundaries of the coarse block by using the fine scale saturation of the adjacent grid block, which has been previously reconstructed. Using this approach we ensure continuity of saturation values at the boundaries of the coarse grid block.

Local fine scale boundary conditions are computed for the particular coarse grid block visited and local flow is performed several times (changing the pore volume injected) until the average of the reconstructed local fine scale saturations \( S_{w}^{fine}(u) \) matches the coarse saturation of the coarse grid block \( S_{w}^{coarse}(v) \). The process is repeated for each coarse grid block until the 2D fine scale saturation map is reconstructed.

### 4.2 Downscaling workflow and results

The workflow used for downscaling saturations at each coarse grid block is shown in Figure 11. The coarse properties \( S_{w}^{coarse}(v) \), \( q_x^c(v) \) and \( q_z^c(v) \) are obtained from the coarse scale flow simulation, where \( q_x^c(v) \) and \( q_z^c(v) \) are total coarse fluxes in the \( x \) and \( z \) directions.

Local fine scale boundary conditions are computed for the particular coarse grid block visited and local 2D two-phase flow is simulated on the \( x - z \) sub-grid and ignoring gravitational forces for now. This flow simulation is performed several times (changing the pore volume injected) until the average of the reconstructed local fine scale saturations \( S_{w}^{fine}(u) \) matches the coarse saturation of the coarse grid block \( S_{w}^{coarse}(v) \). The process is repeated for each coarse grid block until the 2D fine scale saturation map is reconstructed.
We have applied this downscaling procedure to the coarse scale saturation map obtained before (Figure 9), and the result is shown in Figure 12. From this figure we can observe that the fine details of the saturation front are restored and the smooth character has been removed, this without running a global fine scale flow simulation.

![Workflow diagram](image)

**Figure 11:** Workflow used for downscaling coarse scale saturations from the flow simulator.

Using the three saturation maps shown in Figure 12 we have computed the time-lapse synthetic response following the fluid substitution approach explain earlier, and using a traditional zero-offset convolutional model as the seismic forward model. The resulting time-lapse responses are shown in Figure 13.
From this result we can observe that using coarse scale saturations from the flow simulator to perform the fluid substitution on the fine scale model results in a smooth seismic image that does not exhibit the key features we see in the “true” time-lapse seismic (Figure 13 (bottom)).

On the other hand, we also observe that using downscaled saturations to perform the fluid substitution on the fine scale model results in a seismic image that exhibits some of the more important key features we see in the “true” time-lapse seismic (Figure 13(bottom)). However, the strong reflection amplitudes observed at the left of the “true” section are not strong enough in the time-lapse section obtained from downscaled saturations. $S_w = 1$ observed at the left of the downscaled saturation map, is different in geometry from the “true” one, resulting in less acoustic contrast.

The “pulled down” reflection ($t = 1.1$ sec) from the base of the sand interval is correctly restored when using the downscaled saturation map.

Perhaps the most important feature of the “true” time-lapse seismic response are the two middle positive reflections (in blue) which are coinciding at a distance of 2500 meters. This feature corresponds to the seismic response of fine details (below resolution) in the water front, and it is completely reproduced by the time-lapse seismic obtained using the downscaled saturation map.

Figure 14 shows two 4D seismic traces (difference of two 3D seismic traces) extracted from the time-lapse seismic responses obtained using the saturation maps shown in Figure 12. The seismic traces are extracted at the distances of 1000 meters and 3500 meters. These 4D seismic traces clearly show how the time-lapse seismic response obtained using the downscaled saturation map (red curve) reproduces the important features observed in the “true” time-lapse seismic response (blue curve), while the time-lapse seismic response obtained using the coarse scale saturation map (green curve) is systematically off at the middle section of the reservoir.

The 4D seismic trace extracted at 1000 meters shows how the time-lapse seismic response obtained using the downscaled saturation map reproduces the main seismic reflections both in amplitude and time, while the time-lapse seismic response obtained using the coarse scale saturation map does not reproduce the amplitude of the reflections (only reproduces the reflection from the top of the reservoir) and misplaces the reflection time of the bottom of the reservoir.
The seismic trace extracted at 3500 meters shows how the time-lapse seismic response obtained using the downscaled saturation map reproduces the “pinch-out” observed in the “true” time-lapse seismic response, while the time-lapse seismic response obtained using the coarse scale saturation map does not identify it, instead introduces two reflections.
Figure 12: Coarse scale saturation map (top), downscaled saturation map (middle), and fine scale saturation map (bottom).
Figure 13: Time-lapse seismic response obtained using: the coarse scale saturation map (top), the downscaled saturation map (middle), and the fine scale saturation map (bottom).
Figure 14: Two 4D seismic traces extracted from the time-lapse seismic responses obtained using: the coarse scale saturation map (top left), the downscaled saturation map (top middle), and the fine scale saturation map (top right). The seismic trace on the bottom left corresponds to a distance of 1000 meters, and the seismic trace on the bottom right corresponds to a distance of 3500 meters.
5 Conclusions and future research

• The paper shows that a modeled 4D seismic response depends on how the saturations are downscaled from the flow simulation model to the geocellular model.

• A method for downscaling coarse saturations from the flow simulator is proposed and successfully applied. This method does not require any global fine scale calculations. Instead, the method uses global coarse scale flow solutions to determine local boundary conditions for reconstructing the fine scale saturations.

• For the synthetic layered model, it was found that modeling 4D seismic data using downscaled saturations results in a better match with the “true” 4D seismic (flow simulations were possible on the fine scale), because the downscaled saturations reproduce the sharpness and the small details of the water saturation front.

• Modeling 4D seismic data using the traditional approach of simply copying the coarse scale saturation from the flow simulator to the high resolution model results in a time-lapse response that is not able to accurately predict the distribution of fluids in the reservoir.

• Future research will focus on:
  – incorporating gravitational forces into the local fine scale two-phase flow simulations.
  – incorporating the downscaling procedure into the workflow of history matching both production and 4D seismic data.
  – studying the impact the downscaling procedure on other time-lapse seismic attributes such as AVO intercept and gradient.
6 Acknowledgements

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7 References


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