

## Well performance diagnostics by integrating 4D seismic in a coupled fluid flow / geomechanical model

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### Summary

In this paper we present an integrated workflow for modeling and monitoring geomechanical effects in and around a producing reservoir stimulated by injection. The novelty of the workflow is the updates of a coupled fluid flow / geomechanical model based on time-lapse seismic measurements. We here take advantage of new methods for measuring subtle time-shifts and new techniques for detecting (active) fracture sets on 4D seismic. The model calibration step includes dynamic permeability updates, which extend the permitted region of flow to the overburden to facilitate a situation where fluids escape from the reservoir. The extended model gives a first order estimate of the amount of escaped fluids. The presented results are from a reservoir where the cap rock seal was compromised after injecting at high pressure.

### Introduction

Reservoir production and injection change the effective stress state of the reservoir and the surrounding rocks. Sometimes the stress changes lead to fracturing and fault reactivation. The reservoir integrity may then be at risk, and we must be able to mitigate problems like fluids escaping from the reservoir. Time-lapse (4D) seismic can be used to monitor the effects of production and injection. However, to identify whether the observed state is critical, and to estimate the amount of escaped fluids, a coupled fluid flow / geomechanical model is needed. The importance of such coupled models will only increase as more advanced high pressure recovery methods are used and deeper reservoirs are developed.

In this paper we present an integrated workflow for modeling and monitoring geomechanical effects in and around a producing reservoir stimulated by injection. The novelty of the workflow is the model updates based on time-lapse seismic measurements. We here take advantage of new methods for measuring subtle time-shifts (Nickel and Sønneland 2009) and new techniques for detecting (active) fracture sets on 4D seismic (Borgos et al. 2009). The model calibration step includes dynamic permeability updates, which extend the permitted region of flow to the overburden to facilitate a situation where fluids escape from the reservoir. The extended model gives a first order estimate of the amount of escaped fluids. The presented results are from a reservoir where the cap rock seal was compromised after injecting at high pressure.

### Method

The workflow consists of three parts: 1. Building a coupled fluid flow / geomechanical model of the reservoir and the surrounding rocks, based on an existing reservoir fluid flow model. 2. Calibrating the coupled model so that simulated time-shifts match the observed 4D time-shifts in the reservoir. 3. Updating the permitted region of flow by introducing new fluid paths identified on 4D seismic, and estimating the volume of escaped fluids. Figure 1 gives an overview of the workflow.

**1. Model building.** A coupled fluid flow / geomechanical model is built from an existing reservoir fluid flow model. The geometry of the reservoir model is extended with overburden (to seabed), side- and underburden elements so that the extent of the coupled model is ~ 6 times the extent of the reservoir model. We note that the embedded model is consistent with the model repository, which contains all primitives detectable on seismic, including faults, fractures and overburden horizons (Borgos et al. 2007). This is important when studying overburden effects. Furthermore, the embedded model is large enough to minimize boundary effects.

The elastic properties of the model, e.g., Young's modulus and Poisson's ratio, are derived from well-logs and rock physics correlations where applicable. Around the reservoir, log inferred layer cake properties are used. In the reservoir, the elastic properties are given by a porosity correlation. In addition, cohesion and friction angle are given as input. We also include fractures and faults, and specify the regional stress state (ratios and directions). After an equilibrium stress initialization, where the density of the overburden rock is taken into account, the coupled simulation provides fluid flow properties, e.g., pressures, and geomechanical properties, e.g., stresses and strains, at each time step. We note that pressures from the fluid flow simulator are used as input to the geomechanical simulator, which again produces new porosities/permeabilities (modified by stresses and strains) that can be used as input to the fluid flow simulator at the next time level.

## Well performance diagnostics

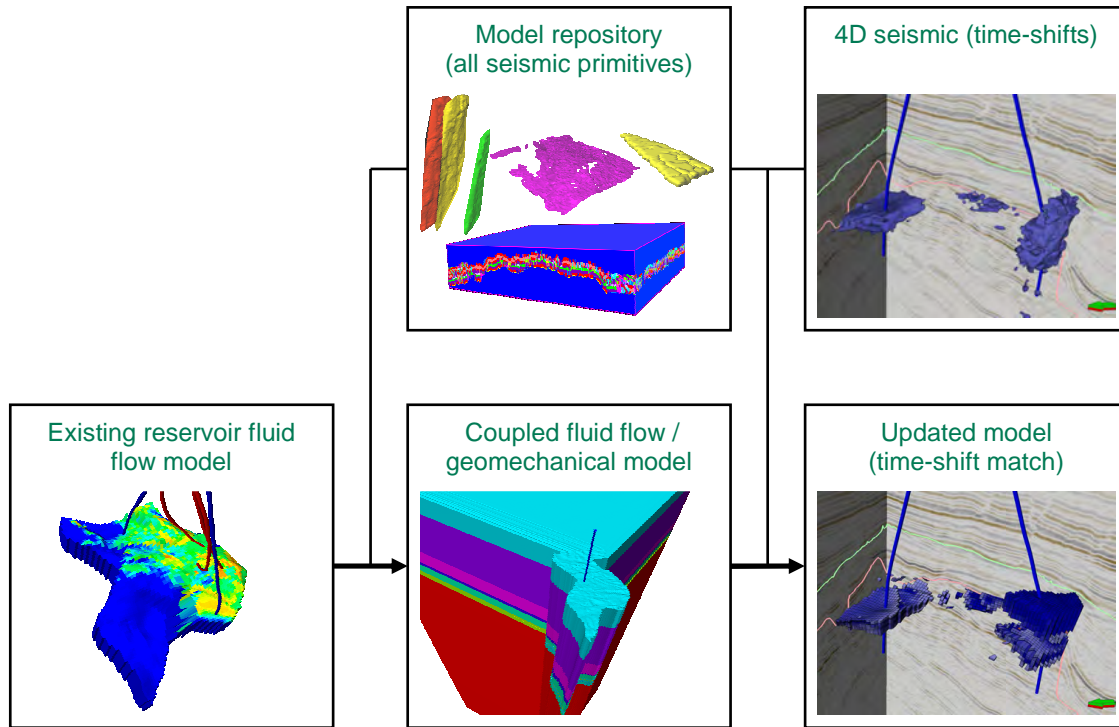


Figure 1: Integrated workflow. First, a coupled fluid flow / geomechanical model is built from an existing reservoir fluid flow model. The coupled model is consistent with the model repository, which contains all primitives detectable on seismic, including horizons, faults and fractures. Then, the coupled model is updated so that it matches the 4D seismic measurements (time-shifts).

2. Model calibration. To calibrate the model against 4D seismic measurements, we calculate pressure and shear velocities  $V_p$  and  $V_s$  by

$$V_p = \sqrt{\frac{K_{sat}(\Delta\sigma_m) + \frac{4}{3}G}{\rho}} \quad \text{and} \quad V_s = \sqrt{\frac{G}{\rho}}, \quad (1)$$

where  $K$  and  $G$  denote the bulk and shear moduli,  $\rho$  is the density and  $\sigma_m$  is the mean stress. In our rock physics model, density depends on saturation and porosity, the shear modulus  $G$  is kept fixed in time, while the saturated bulk modulus  $K_{sat}$  is calculated by a Gassmann approximation, combining the effective fluid bulk modulus (saturation weighted through Wood's equation), the effective solid bulk modulus and the skeleton bulk modulus, which is updated by

$$K_{skel}^{n+1} = K_{skel}^n + a(\sigma_m^n, \varphi^n)(\sigma_m^{n+1} - \sigma_m^n) \quad (2)$$

Here,  $a$  is a function of mean stress and porosity, and superscript  $n$  denotes time level  $n$ . We note that this update is only used for the velocity calculation. The elastic material properties used in the coupled simulation remain fixed.

Furthermore, the change in p-velocity between two time-lapses is combined with the simulated vertical displacement (compaction or uplift) to produce a relative time-shift estimate,

$$\frac{\Delta t}{t} = \frac{\Delta z}{z} - \frac{\Delta V_p}{V_p}, \quad (3)$$

(Landrø and Stammeijer 2004). Here,  $(\Delta z / z)$  represents the vertical strain and  $(\Delta V_p / V_p)$  is the relative pressure velocity change. This relative time-shift estimate is compared with the time-shifts observed on 4D seismic. Model calibration is done by adjusting model parameters and the function  $a$  in Eq. (2) so that the simulated time-shifts match the observed time-shifts.

## Well performance diagnostics

3. Updating permitted region of flow and estimating escaped volume. Using time-lapse seismic, we can possibly detect fluid flow paths not captured by the current model, for instance caused by fracturing or fault reactivation. Of special interest in this work is the detection of dynamic changes to seismic discontinuities (Borgos et al. 2009), which can be interpreted as fractures opening up and creating new flow paths. The direction and density of these fracture sets are easily incorporated in our coupled model. Furthermore, we can model the dynamic behavior of the fractures by modifying the permeability as a function of calculated fracture normal strain. Consequently, fluid flow out of the reservoir caused by fracturing the cap rock can be described by a cap rock permeability which is zero initially, but becomes non-zero when the fracture normal strain exceeds a threshold value.

Fluids escaping from the reservoir will produce pressure and fluid effects in the overburden. These subtle effects can be observed as time-shifts on 4D seismic (Nickel and Sønneland. 2009). By updating the permeability in the region of escaped fluids so that the simulated time-shifts match the observed time-shifts, we can argue that the modeled flow out of the reservoir matches the observed flow out of the reservoir. Consequently, the simulated net inflow into the extended region of flow gives a first order estimate of the volume of escaped fluids. Additional data is needed to improve this estimate.

### Example

We have applied the workflow described above to a reservoir where the cap rock was fractured due to a high injection pressure. In addition to the injector causing the fracturing, the reservoir has one more injector and two producers, and two time-lapse seismic surveys have been acquired.

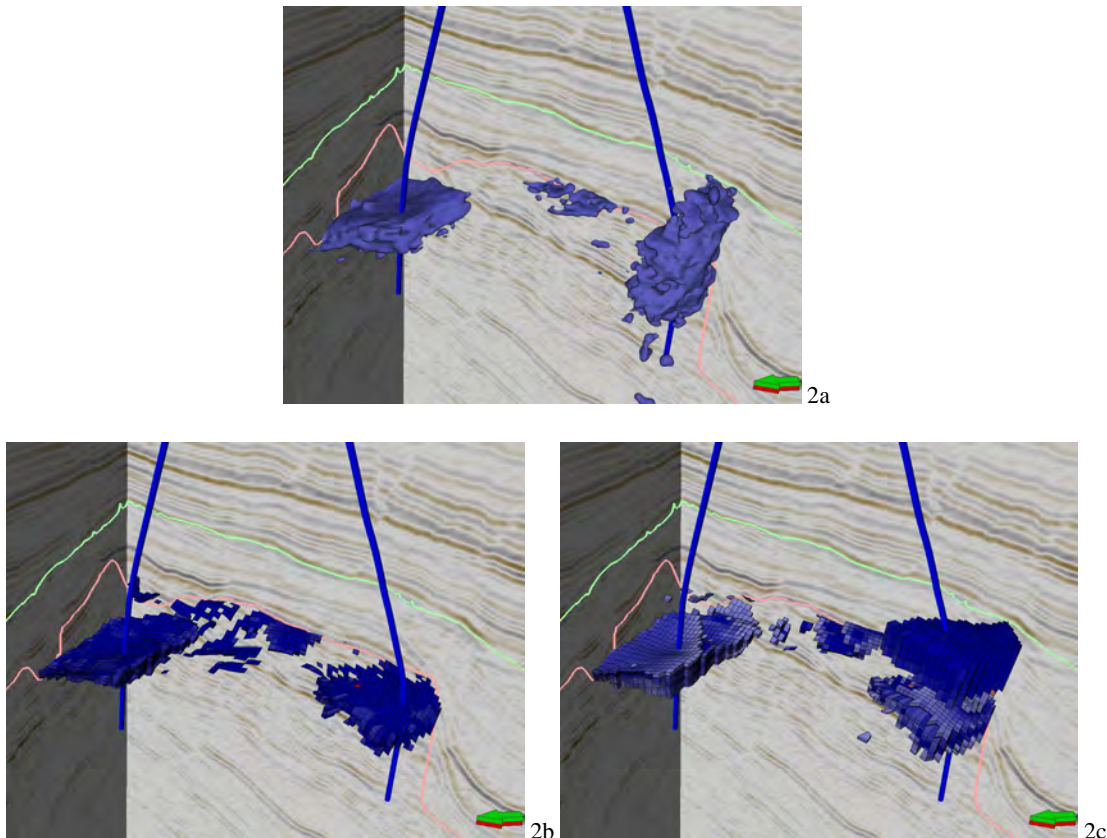


Figure 2: Measured time-shifts (2a), simulated time-shifts with original coupled model (2b) and simulated time-shift with updated model, including flow into the overburden (2c). Only samples / grid cells with positive time-shifts are shown, and the color intensity reflects the time-shift value. The pink line on the seismic is the Top Reservoir horizon, while the green line is a horizon in the overburden.

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Figure 2a illustrates the positive time-shifts measured in a set of samples around each injector. For the leftmost injector, the time-shifts are limited by the top reservoir horizon. The time-shifts around the rightmost injector extend into the overburden, indicating that fluids have escaped from the reservoir. We note that, since the vertical displacement was found to be negligible, a positive time-shift corresponds to a velocity decrease, according to Eq. (3).

As Figure 2b shows, we got a qualitatively correct picture of the velocity changes around the leftmost injector even with the original model. However, without including fluid flow out of the reservoir in the model, we could obviously not match the measured time-shift around the other injector, especially not in the overburden.

Using new techniques described by (Borgos et al. 2009), a set of seismic discontinuities growing in size and extent was identified, suggesting that the fluid flow out of the reservoir was caused by fracturing. We therefore included a weak fracture set in the model, reaching from the cap rock into the overburden. The fracture set was consistent with the observed discontinuities, and we assigned a permeability modification function to the fracture set to account for fracture opening.

Figure 2c shows the effect of introducing a non-zero permeability in the overburden due to fracture normal strain, and adjusting the function  $a$  in Eq. (2) to improve the time-shift match in the reservoir. Compared to the original model (Figure 2b), the match is improved both qualitatively and quantitatively. We note that the calculated overburden time-shifts suffer from lack of accurate material property data. This is subject to further work.

For each overburden cell, we also considered the simulated pressure difference, the net inflow, the calculated time-shift and the measured time-shift. The volume of escaped fluids was estimated as the sum of net inflow into all overburden cells. In addition, we looked for a correlation between the observed time-shifts and the estimated escaped volume. However, the results were not conclusive, and need to be examined further.

### Conclusions

We have developed and tested a workflow for modeling and measuring geomechanical effects in and around a producing reservoir stimulated by injection. The use of an integrated workflow combining advanced time-lapse seismic measurements and a coupled fluid flow / geomechanical model allowed us to rapidly incorporate the changes observed on the time-lapse seismic in the coupled model. The modification of the permeability as a function of fracture strain enabled us to simulate fracturing of the cap rock, and calculate a first order estimate of the volume of escaped fluids.

Further work includes improving the accuracy of the escaped fluid volume estimate, and studying the effect of adjusting different model parameters when matching observed time-shifts. The correlation between observed time-shifts and escaped fluid volume will also be studied further.

### Acknowledgments

We would like to thank StatoilHydro and the license partners ENI Norge and Petoro for providing the dataset. We also thank the Schlumberger Reservoir Geomechanics Centre of Excellence, Bracknell, UK, for help and assistance.

### **EDITED REFERENCES**

Note: This reference list is a copy-edited version of the reference list submitted by the author. Reference lists for the 2009 SEG Technical Program Expanded Abstracts have been copy edited so that references provided with the online metadata for each paper will achieve a high degree of linking to cited sources that appear on the Web.

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