Time-lapse seismic data-calibrated geomechanical model reveals hydraulic fracture re-orientation
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Summary
The orientation and size of fractures created during hydraulic stimulation is governed by the in-situ stress state. Reservoir production changes both the magnitude and the direction of the principal stresses, and these stress changes can be calculated using a geomechanical model. In this study, we employ a 4D geomechanical model calibrated with time-lapse seismic time shift data to understand the direction of fracture growth during hydraulic stimulation of a horizontal injector well. The horizontal well was drilled in the (expected) direction of the maximum horizontal stress, such that the strike direction of the fractures is aligned with the wellbore axis. Our study shows that production from a nearby well has rotated the directions of horizontal stresses, and some of the hydraulic fractures now grow perpendicular to the wellbore axis. The stress-field calculations and predicted directions of hydraulic fractures are substantiated by the observed time-lapse seismic amplitude signal. This signal shows increased fluid flow in the predicted fracture direction for individual stimulated zones.

Introduction
Geomechanical models have many purposes in reservoir management. Applications include the prediction of reservoir compaction and subsidence, long-term well-bore integrity, optimization of drilling trajectories and mudweights, and the design of hydraulic stimulation and perforation campaigns. The basis for all geomechanical applications is an accurate knowledge of the subsurface stress state and the mechanical properties, in combination forming a geomechanical (or mechanical earth) model. To increase trust in their predictions, these models need to match data observations. For example, time-lapse seismic time shifts in the overburden are now commonly ascribed to reservoir compaction and ensuing overburden elongation and associated velocity slow-down (Hatchell and Bourne, 2005). The link between these time shifts and the overburden elongation is now being used as a field-wide calibration tool for geomechanical models (Staples et al., 2007; Herwanger and Koutsabeloulis, 2011).

In a previous study (Herwanger et al., 2010, Fig. 1a and 1b)

Figure 1: Observed and calculated reservoir compaction. (a) Map of observed time-lapse timeshifts at reservoir top during 6 years of production. Positive timeshift show an increase in two-way traveltime from base survey to monitor survey, indicating overburden stretching and associated velocity slowdown. (b) Vertical displacement of reservoir top, calculated from a 3D geomechanical model during the time-period covered by the time-lapse seismic survey. Negative displacement indicates a downward movement. Note the difference in shape between (a) observed and (b) calculated compaction features outlined by the yellow and magenta lines. (c) Calculated vertical displacement of the reservoir top after updating porosity distribution and rock failure parameters in geomechanical model.
we compared observed time-lapse time shifts and reservoir compaction calculated from a geomechanical model, respectively. The results show a broad agreement in compaction features but indicate possible improvements to the geomechanical model to more closely match the compaction observations. In the first part of this paper, we therefore describe how to update the 3D geomechanical model by adjusting the porosity distribution and the rock failure model, and show the ensuing improved fit of predicted compaction to observed time shifts.

In the second part of the paper, we use the time-lapse seismic-calibrated geomechanical model to investigate the direction of hydraulic fracture growth. We show that reservoir production can cause re-orientation of stresses and therefore a re-orientation of azimuth of these fractures. The time-lapse seismic signal shows elongated structures around individual well completions that are aligned with the predicted fracture azimuths, further corroborating the predictive power of the geomechanical model.

Quality control of geomechanical model using time-lapse seismic data

For this study a 3D seismic base-line survey and a monitor survey, acquired in 1995 and 2005, respectively, were used (Schiøtt and King, 2006). Both time-lapse time shift signals (related to reservoir compaction) and time-lapse amplitude changes (related to water replacing oil and to reservoir compaction) provided clear time-lapse seismic attributes that are utilized at South Arne for seismic reservoir monitoring (Schiøtt et al., 2008, Herwanger et al., 2010). Observed time-lapse time shifts measure the increase in two-way traveltime to the top-of-reservoir reflector (Figure 1a). The time shifts can be compared to vertical displacement of the reflector, calculated from a 3D geomechanical model coupled to a reservoir flow simulation model (Figure 1b). Assuming a linear relationship between the two quantities (Hatchell and Bourne, 2006, equation 3), the maximum observed time shifts of 6 ms translate into vertical displacements of 1.0 m, when assuming an average velocity of the overburden of 2000 m/s, a strain sensitivity factor of R=5 and no seafloor subsidence. There is a broad agreement in observed and predicted compaction (general areal extent and magnitude of the compaction feature) but marked differences in detail. For example, the lateral position of the center of the compaction feature outlined in yellow moves 500m to the north-west between observation (Figure 1a) and prediction (Figure 1b). Similarly, the compaction feature outlined in magenta is markedly more elongated in the compaction calculations (Figure 1b) than in the compaction observations (Figure 1a), and the area drained by the eastern-most well shows no observed compaction, but a large amount of vertical displacement is predicted. Clearly, the geomechanical model can be updated so that the compaction calculation using the geomechanical model more closely matches the observed compaction.

The main controls on reservoir compaction are the geometry of the reservoir, the amount of pore pressure reduction, the porosity distribution and the stress state at which the onset of inelastic compaction starts to occur (rock failure model). The geomechanical model parameters we judged to be most uncertain, as well as the major control parameters, are the porosity distribution and the rock failure model. A site-specific chalk failure model was developed by Hess, based on new laboratory measurements on chalk samples from the reservoir. The model follows the generally accepted trend of high-porosity chalk showing a low effective stress at which the onset of failure occurs, and the low-porosity chalk as more competent and with higher failure stress. At the same time, the 3D porosity distribution was updated in the simulation model to honor seismic data and inversion models from the 2005 seismic survey (Schiøtt et al., 2008).

The new geomechanical model shows a markedly different

Figure 2: (a) Hydraulic fractures open such that the fracture normal is aligned with the minimum principal stress. (b) Horizontal wells in unconventional reservoirs are often drilled in the direction of minimum principal stress, and hydraulically stimulated fractures grow perpendicular to the wellbore axis. (c) For water-flooding, horizontal wells may be drilled in the direction of maximum horizontal stress (here the intermediate principal stress), and the strike direction of the hydraulically stimulated fractures aligns with the wellbore axis.
compaction pattern from the first geomechanical model (compare Figures 1b and 1c, for first and updated geomechanical model, respectively). The calculated compaction features (Figure 1c) now closely match the ones observed from time-lapse seismic time shifts (Figure 1a), and the new geomechanical model is deemed to be quality controlled by the time-lapse seismic data.

**Reservoir stress state and hydraulic fractures**

The South Arne field (Mackertich and Goulding, 1999) in the Danish sector of the North Sea started production in 1999, from horizontal wells. Because of the low permeability of the chalk reservoir formations (0.1 to 10mD matrix permeability), the production wells are hydraulically stimulated to enhance production rates and increase the amount of recoverable oil. For pressure support, the production wells are interspersed with horizontal water injection wells for pressure support.

As a general rule, hydraulic fractures open against the direction of the minimum principal stress, and the fracture plane contains the intermediate and maximum principal stresses (Figure 2a). There are different strategies for hydraulic stimulation of horizontal wells. For example, in unconventional reservoirs, horizontal wells are often drilled in the direction of the minimum principal stress, with a resulting fracture pattern, as displayed in Figure 2(b), maximizing reservoir contact from a single well (Brady et al., 1992). At South Arne the horizontal production and injection wells are drilled in the direction of the maximum horizontal stress (Figure 2c), and hydraulically stimulated. The conceptual idea behind stimulating water-injection wells in such a manner is to create a “water wall” within the fractures, which then “pushes” the oil uniformly toward the producer.

To understand hydraulic fracture growth, we investigated the stress directions using the calibrated geomechanical model. Before start-up of reservoir production, the direction of the maximum horizontal was aligned with the direction of the horizontal production and injection wells (see Figure 3a). Production from Well P1 started in September 1999. By June 2000, after 8 months of production, the injector Well I1 had been drilled and stimulation took place from June to September 2000. We therefore display the calculated stress state in June 2000, in Figure 3(b), as being representative for the stress state at the time of stimulation. We display the magnitude and direction of the maximum horizontal stress (which is the intermediate principal effective stress in a normal stress regime such as at South Arne). Comparison between Figures 3(a) and 3(b) shows, as expected, that the (effective) stress magnitude has increased as pore pressure decreased during the 8 months of reservoir production. Somewhat less expected is the marked re-orientation of stress direction of up to 90° in parts of the field.

![Figure 3](image-url) (a) Magnitude and direction of maximum effective horizontal stress $\sigma_{H}$ before start of reservoir production. Trajectories of production Well P1 and injection Well I1 are aligned with direction of $\sigma_{H}$. (b) At the time of hydraulic fracturing of Well I1 after 8 months of production from Well P1.
Geomechanical model calibration and application

The stress re-orientation along the well trajectory of injector Well I1 impacts the azimuth of hydraulically induced fractures. Therefore the direction of $\sigma_H$ at each perforation along I1 is highlighted by white bars. The azimuth of the white bar also represents the azimuth at which a hydraulic fractures will propagate. Note that this azimuth is aligned with the well trajectory at the toe and heel of the well, rotates slowly approaching the center of the well, and is perpendicular to the well trajectory in the center of the well.

This stress-field behavior implies that the hydraulic fractures do not grow as intended to form a single large-scale vertical fracture whereby the well direction gives the azimuth of the fracture. Instead, a series of discrete en echelon fractures with rotating azimuths are formed along the trajectory of Well I1. Some of these fractures are predicted to grow toward the production well, potentially accelerating water breakthrough between injector Well I1 and production Well P1. Modeling of fracture geometry (height, width and shape) is of significant interest but is not part of this paper. Modeling of individual fractures is described in Vejbæk et al. (2013).

Corroboration of fracture azimuth by time-lapse amplitude changes

By the time the monitor survey was acquired in autumn 2005, water injection at Well I1 had taken place for more than 4 years. We therefore investigated whether the movements of the waterfront seen by time-lapse seismic amplitude analysis (Herwanger et al., 2010) could give further insight into the stimulation process.

In Figure 4 we plot the interpreted change in water saturation $\Delta S_w$ in map view, averaged across the reservoir interval. The water flood created by water injection into Well I1 clearly stands out, with subtle features of larger water saturation changes (dark shades of blue) discernible around individual stimulated zones. The most prominent features are outlined in yellow. Similar observations have been used to derive (relative) injection and production rates along wells by Gouveia et al. (2004) and Barkved et al. (2009), and are sometimes loosely referred to as “seismic production logging tool”, or “seismic PLT”. Other noteworthy features include the termination of water saturation changes against interpreted faults, indicating sealing faults.

Of particular interest is the elongation of subtle injection features whereby the direction of elongation coincides with the direction of predicted fracture growth (i.e., the directions of the yellow arrows, indicating direction of fluid flow, coincide with the directions of red arrows, indicating azimuth of hydraulic fractures). We believe the observation indicates increased injectivity and fluid flow along the hydraulically induced fractures.

Figure 4: Observed change in water saturation (shades of blue) during water injection in Well I1 aligns with predicted fracture azimuth.

Conclusions

We used a geomechanical model to better understand the growth of hydraulically induced fractures. As a result of reservoir production, an unexpected re-orientation of principal stress directions caused a rotation in the azimuth of the stimulated hydraulic fractures, and some hydraulic fractures now grow in a direction perpendicular to the wellbore. These calculations require a full-field 3D geomechanical model. A 1D geomechanical model would not be sufficient to calculate and predict the stress-field re-orientations. Full field geomechanical models require calibration across the entire field. In this study we used observed seismic time-lapse time shift data to quality control the predicted compaction with observed time shift signals. Inclusion of the seismic data for areal calibration increased the predictive capability of the 3D geomechanical model. By combining time-lapse seismic data with geomechanical models and jointly interpreting the results, we gained a deeper insight into the nature and genesis of hydraulic fractures than could have been achieved by using the methods individually. The calibrated geomechanical model can now serve as an input to modeling fractures emanating from individually stimulated zones.

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EDITED REFERENCES
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