Geology and field history

The Edvard Grieg field was discovered in 2007 with Lundin Norway’s very first drilled exploration well, and production started in late 2015. The total expected recoverable reserves as per 2019 is around 270 mmboe, of which ~30% has been produced during the three first years of production. The reservoir zone sits in a half graben at approximately 1900-2000m depth. It consists of an upper Aeolian sand dune high permeability zone underlain and mixed with shales and conglomerates. Understanding the areal distribution of the conglomerates and the high porosity sandstones is a critical component in the reservoir development of the field. Some parts of the field also consist of thin cretaceous sands draped on top of weathered fractured basement with varying porosity. The ability to distinguish lithology and fluid parameters in a reservoir setting consisting primarily of three very different facies has been the main driver behind adopting more complex and data driven inversion methods. For more information on the Edvard Grieg please consider Dhelie et. al (2015).

Simultaneous Wave-Equation Based AVO Inversion of Seismic Time-Lapse Datasets

In this paper we demonstrate a simultaneous wave-equation based AVO technology (Sim4D WEB-AVO) for quantitative interpretation of 4D OBC data over the Edvard Grieg field. In general, the inversion technique, on single vintage 3D data, solves the elastic wave-equation iteratively, whereby in every iteration a higher order of multiple scattering is accounted for (Gisolf et al. 2017). This is depicted in Figure 2. The approach is based on the fact that the relationship between the data and the properties to invert for is non-linear. This non-linearity can be expressed in a functional Taylor expansion of the data in powers of the properties. In every iteration in Figure 2, a higher order term is calculated. The higher powers take care of all non-linear effects such as internal multiple scattering, mode conversions and transmission effects, as well as the differences between the travel times in the real medium and the travel times in the background medium. This non-linear relationship also allows us to recover a wider spatial bandwidth for the properties than could have been expected on the basis of the temporal bandwidth of the seismic data. In traditional terms one could say that wave equation based inversion automatically takes care of de-tuning of the data. Experience has taught us that this method is robust against noise and local minima in the inversion.

Given the non-linearity discussed above, it should be clear that in a time-lapse 4D setting we should not subtract data-sets, but we should subtract the inversion results for the various vintages to get a true picture of where time-lapse changes are occurring. Inverting two data vintages simultaneously gives the extra advantage that we can impose constraints on the time-lapse property differences. In this paper we impose sparseness of the time-lapse property differences, while the base-line and monitor properties itself are not sparse at all. This gives an even more robust inversion.

![Figure 1 Geographic location of the Edvard Grieg field in the Norwegian sector of the North Sea.](image)

![Figure 2 Schematic description of iterative wave-equation based inversion.](image)
Another unique feature of the method is that it solves directly for compressibility $\kappa$ (inverse of bulk modulus) and shear compliance $M$ (inverse of shear modulus $\mu$) instead of impedances as obtained by conventional linear AVO techniques. Compressibility and shear compliance are highly suitable for quantitative interpretation, in particular time-lapse interpretation, because compressibility is three times more sensitive to fluid changes than acoustic impedance, whereas the shear compliance is responsive to pore pressure changes only (Haffinger et al. 2017).

**Data input and inversion workflow**

For the current study two seismic OBC data-sets were used, which were acquired over the Edvard Grieg field in 2016 and 2018. The data was imaged using a Kirchhoff depth migration flow, in order to create pre-stack gathers suitable for AVO inversion. A clear time-lapse signal was visible on the full stacks while the 4D signal was quite less pronounced in the pre-stack domain. To improve this situation, spectral shaping, dip-filtering and a structurally oriented filter (SOF) were applied on both the base-line and the monitor datasets. While this procedure notably enhanced the 4D signal, no time-lapse effect could be observed at the three calibration wells that were used in this study (see Figure 3a). This implies that no quantitative quality control of the inversion with respect to the time-lapse property changes could be performed. Wavelets were therefore estimated for the baseline survey only and assumed to be unchanged for the monitor dataset. A low-frequency model was used that had been prepared for a previous 3D inversion project over the same field (Dhelie et al. 2019). Logs of the three wells were high-cut filtered ($f_{\text{max}} = 8$ Hz) and interpolated using the inverse distance weighting method, while taking the main geological structure (picked horizons) into account. The inversion result along an arbitrary line connecting the three well locations is shown in Figure 3.

![Figure 3 Stack of 4D difference (monitor-baseline) of seismic input gathers (a), stack of difference of predicted synthetic gathers (b), inverted baseline compressibility (c), and inverted time-lapse effect in terms of compressibility (d). The sparseness parameter has been set in order to match most of the expected 4D signal over the reservoir interval while suppressing noise both above and below.](image)

**Interpretation and discussions**

In this study we have evaluated the possibility to use the derived time-lapse compressibility data from simultaneous 4D wave equation based inversion to estimate quantitatively saturation changes in the upper reservoir intervals. The observed hardening on stacked time-lapse seismic is interpreted as water replacing oil. An unsuccessful attempt was made to incorporate coupled pressure & saturation effects, notably gas out of solution in conglomeratic facies along the east flank of the field. For comparison we have also used the conventional time-lapse PP amplitude data. In order to establish a relationship between relative changes in compressibility, or NRMS-amplitudes and changes in saturation, we have
carried out simple 1D modelling using a key exploration well (see Figure 4). The good quality main sandstones in this well are representative of the area observed on PP time-lapse seismic. By using such a simple relationship, we are not considering time-shift induced changes. Consequently, it is very important to remove all time-shifts in the PP amplitude data, if one were to work with the seismic amplitude changes directly.

![Figure 4 1D modelled relationships between relative changes in compressibility (left) and NRMS-amplitudes (right), and changes in saturation.](image)

The left panel in Figure 5 shows a map view of the relative changes in compressibility averaged over the upper reservoir interval, while the middle panel shows the resulting saturation changes using the relationships shown in Figure 4. Considering an initial oil saturation in the main sands close to 90%, and an immobile oil saturation of ~20%, the maximum estimated saturation change is in good accordance with a fully swept main sand reservoir. Compared with the current simulation model shown in right-hand-side panel of Figure 5, the swept areas are considerably smaller than modelled. However, the advancement of the water front is known to be too high in the simulations, and the mapped fluid effect areas shown in Figure 5 are considered to be a more realistic representation of the swept areas. The corresponding map of the saturation changes estimated from NRMS-amplitudes directly displayed in Figure 6 shows a higher maximum saturation change compared with the map derived from the compressibility. This is probably due to not being able to accurately correct for time-shifts in the PP amplitude data, giving too high NRMS compared with 1D modelling. Consequently, using the simple 1D relationship on the PP amplitude data will over-estimate the saturation changes, thus exceeding the maximum recovery factor. On the other hand, the new simultaneous 4D inversion automatically handles these time-shifts.

**Conclusions**

A very successful seismic 4D campaign consisting of two vintages of data, 2016 and 2018, yielded excellent time-lapse seismic data. Clear fluid effects showing injected water sweeping oil towards the producers are easy to interpret. To obtain a quantitative interpretation of the saturation changes a simultaneous 4D wave equation base inversion has been performed. The resulting time-lapse compressibility data were successfully used to estimate saturation changes due to water replacing oil in the Aeolian sand reservoir on Edvard Grieg. The resulting saturation maps can be used directly for conditioning the simulation model for optimum history matching.

**Acknowledgements**

We would like to thank PL338, with the operator Lundin Norway and the partners Wintershall Dea and OMV for their continued support and permission to publish this work.
Figure 5 The relative changes in compressibility as derived by Sim4D WEB-AVO inversion (left) can be translated into saturation changes (middle) using the relationship shown in Figure 4. Right most panel show the saturation change in the current simulation model for comparison.

Figure 6 NRMS-map from PP amplitude data (left) can be translated into saturation changes (right) using the relationship shown in Figure 4. Notice that the estimated saturation changes exceed what is physically realistic in terms of fluid replacement. This is due to not being able to accurately correct for the time-shift induced amplitude changes.

References


