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Intra-survey Pressure Variations - Implications for 4D Seismic Interpretation

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SUMMARY

During the time taken for seismic data to be acquired, reservoir pressure and saturation may fluctuate as a consequence of field production and operational procedures. This has consequences for the quantitative analysis of 4D seismic data and particularly for understanding of the pressure signal that diffuses rapidly into the reservoir over a time-scale of hours or less. A modelling study using actual acquisition data (permanent seabed sensors and also towed streamers), reveals that the signature of pressure variations in the pre-stack domain is complex, and thus the resultant post-stack image is not representative of the true reservoir mechanisms that caused the pressure changes. This is of particular concern when trying to accurately resolve small pressure changes away from wells with post-stack data. It appears however that larger signals closer to the well may still be detected adequately. Our results have implications for post-stack quantitative 4D seismic analysis, as well as processing and acquisition workflows for detailed seismic time-lapse studies.
Introduction

Estimation of pressure changes across the reservoir is currently based on well measurement (for example: production logging tools and downhole gauges) and extrapolation using subsurface fluid flow simulation models. 4D seismic data may also sense these changes, and it is one of the main objectives for 4D seismic technology to perform the equivalent of a spatial pressure test on a field to determine its overall hydraulic connectivity. However, quantitative estimation of pressure changes across the reservoir using 4D seismic data is well known to be challenging (Eiken and Tøndel 2005). Many possible factors have been held responsible for this, such as: non-repeatability noise, rock stress sensitivity, geomechanical stress re-distributions, stress-unloading/damage of core plug samples, time scale of production versus laboratory, and shale effects (Alvarez and MacBeth 2014). In this study we introduce a new finding, which also adds to these arguments and warrants further future consideration. This relates to the time scale of seismic data acquisition relative to that of the pressure fluctuations themselves. During seismic acquisition (offshore or onshore) over many weeks, pressure variations induced in the field are captured in a non-obvious and irregular way across the pre-stack volume. Thus the post-stack (and migrated) data do not adequately reflect the spatial distribution of the true absolute pressure, but provide instead a complicated smeared and distorted average. The purpose of this study is to determine whether this effect is significant, and assess the impact it may have on our current 4D seismic interpretation practices. This is achieved by the use of modelling with real field acquisition and production data.

**Figure 1** Examples of familiar processes that might occur in the reservoir at the same time as seismic data are acquired. Of particular interest are those effects with similar time scales to the surveying. For the water injector investigated in this study, the water front develops slowly, so that it can be viewed to be stationary over the period of acquisition. The pressure by contrast varies quickly over hours or less.

**Time scale of acquisition versus production behaviour**

Offshore seismic surveys shot to acquire data for monitoring purposes as part of a 4D seismic programme take many weeks to complete. The duration of the surveys is dependent on many practical factors such as the geometry of acquisition, boat speed, boat turn-around, spatial coverage required, and offset coverage. These are amidst other influences such as the effect of tides, platform and facility obstructions, general field activity and bad weather down-time which can typically run into days. Thus, for example, both towed streamer (Campbell et al., 2005) and permanent reservoir monitoring (Eriksrud 2014) surveys are most often acquired in a fairly randomized fashion with time scales ranging from 6 to 8 weeks. However, a range of random independent activities can also occur during the acquisition time that can induce pressure changes in the reservoir and its associated transients (Figure 1). These are controlled by operations management, and are specific to the well and field under consideration. Understandably, operations engineers would prefer that wells are in a steady state (constant flows), but in reality this is not the case. Some well activities possess similar time scales to the acquisition, for example: injector or producer well shut-off or re-start/start, alteration of a rate/choke setting, well tests, bumping/slugging, squeeze treatment where producers are typically shut-in for 12 hours. Turn-arounds, production optimisation, work-overs, evolving water cuts, and the introduction of new wells or re-introduction of old wells all add to this mix. Such well interventions can lead to localised pressure changes, and as pressure by its nature evolves/diffuses rapidly over a short time scale of hours after each significant change, the overall pressure field in the reservoir is
affected (depending on compartment size and properties). To illustrate this behaviour, the pressure variations of a single injector re-started during the actual acquisition of a permanent seabed system are superimposed upon the time scale of the acquisition (Figure 2(a)). Figure 2(b) shows the randomised nature of the shooting, which aimed to optimise time available and negotiate field operations and weather windows.

![Figure 2](a) Seismic acquisition activity histogram for a permanent reservoir monitoring survey superimposed on the pressure fluctuations of an injector well turned on during the acquisition. In the seismic survey, there are gaps at days when no data are acquired. (b) Geometry of seismic sources colour coded by the time sequence in days of shooting, with receivers overlain. The survey is not shot in a regular sequence covering the subsurface.

**Modelling analysis**

To understand the impact of the above intra-survey pressure variation on the time-lapse seismic data, we consider the example of an injector switched on 15 days into the shooting of a PRM survey as in Figure 2(a). Reservoir simulation is performed for a model of a uniform reservoir and a single injector, with a producer active outside the survey area (smaller than the seismic modelling area). The model is built based on the characteristics of a real North Sea field, but the reservoir simplified to a flat uniform reflector and homogenous overburden. The reservoir has a porosity of 21%, net-to-gross 0.7, reservoir thickness 30 m, permeability in X, Y and Z directions of 500 mD, 500 mD and 250 mD respectively.

![Figure 3](a) Histogram of time-stamped common midpoints (CMPs) sorted into each 50 × 50 m bin showing the time variability across a particular CMP bin. The resultant stacked trace in each CMP bin is an average from a combination of traces acquired at different times that have imaged different pressure variations before and after the injector is switched on.
The reservoir is under-saturated with initial water saturation 22% and initial pressure of 23.5 MPa. The simulation is run at fine-scale time steps of two hours to accurately determine the behaviour of a constantly injecting well with a rate 25,000 stb/day. The resulting field pressure and water saturation changes that occur during that time are then converted into seismic properties using a petroelastic model calibrated for the North Sea (Alvarez and MacBeth 2014), from which pre-stack reflection amplitude is computed. The source acquisition coordinates and timing of a real PRM survey are used to model the individual common mid-point data with the offset-dependent convolutional model (Amini 2014). Due to the large amount of available acquisition coordinates, source activations are decimated to every two hours and only these are considered. This also determines the numerical simulation time step above. The time stamped CMPs are then sorted into bins of 50x50m, corresponding to the simulation model grid, for ease of computation. A typical time distribution of CMPs in a bin is shown in Figure 3. CMPs are gathered into near-offset (less than 500m) and far-offset (1500m to 2500m), and then stacked. Finally, time-lapse amplitudes are created by differencing the resultant amplitude response from that prior to the production period. Similar results are found for higher fold images created by including sources that were activated every 10 minutes and finer simulation runs.

Results

The resulting map for the pressure-only seismic amplitudes is shown in Figure 4, together with the predicted responses for a fictitious ‘instantaneous’ acquisition, shot on the 25th and 44th day of production for reference. The injector creates a symmetric pressure distribution, spreading progressively outwards over time from the well, and eventually establishing an equilibrium with the boundaries of the model. The spatio-temporal character of this signal relative to the seismic acquisition, mixes the pressure sampling within each bin, which in turn causes the uneven time-lapse amplitude distribution. The time-lapse seismic amplitudes therefore do not represent either the situation before the injector, or after, but some complex spatio-temporal pre-stack mixture of the two. The images are distorted by the acquisition geometry and timing of the shooting. Qualitatively, the central image of the injector is clearly visible and can be interpreted, but quantitatively the overall shape is not correct, particularly with the smaller pressure changes. When coupled with non-repeatability noise, this would make interpretation difficult, and some features may be easily mistaken as having a geological origin. Furthermore, the near and far offset images sample the pressure change differently, which may be problematic for sophisticated time-lapse seismic analyses incorporating these data. Mean errors relative to the reference ‘instantaneous’ image at day 25 are of the order of 23% for near-offset amplitudes and 21% for the far-offset amplitudes - which are significant and cannot be ignored. The smallest error is around the injector itself, and error increases away from the injector location. Interestingly, due to the compact nature of the much slower water-flood progression during the intra-survey/injector period, water saturation (not shown) is relatively unaffected by the effects described above. That is, the pre-stack and post-stack time-lapse signatures appear very similar. Modelling studies for towed streamer and land acquisitions provide similar insight. In practice, the effect is locked into the post-stack image, smeared by migration and structural complexity.

Discussion and conclusions

Pressure variations caused by field operations during the shooting of a time-lapse acquisition can create a complicated spatio-temporal signature imprint on the pre-stack data. This signature does not translate into a clear post-stack image of the pressure. Therefore, during the acquisition of monitor surveys for time-lapse acquisition, care must be taken to understand the production engineering domain to avoid this occurring. The same is not true of water saturation changes. This modelling work with real acquisition data and fluid flow simulation reveals a number of important points:

- Ideally time-lapse acquisition must be performed during a quiet period of pressure equilibration in the reservoir lifecycle, can this be guaranteed? Should this be necessary?
- Quantitative analysis of pressure changes should be made in the pre-stack domain, not post-stack.
- Quantitative analysis of water saturation changes may be accurate in the post-stack domain.
- The time-scale of the survey relative to the well behaviour needs to be precisely defined in a time-lapse project – usually only one exact time is quoted for the survey, which is incorrect.

Care must be taken in practice to assign times correctly to the survey.
Near and far-offsets sample pressure differently, which may affect time-lapse analysis to separate changes of saturation and pressure.

The comments above may also have a strong impact on pressure-related phenomena such as gas out of solution (Falahat et al. 2014).

**Figure 4** Pressure-driven time-lapse amplitude, taking into account acquisition timings relative to a single injector behaviour. Mapped amplitudes are individually normalized, and are shown at: (a) early and late life of the injector (assuming the survey was shot instantaneously), and (b) the resulting near and far offset images for a PRM survey. The dissimilarity at the near and far offsets suggests that the pressure image is significantly affected by the time sequence of shooting relative to well activity.

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**References**