## Introduction

Using sources on the surface and receivers close to the formation structure of interest, Vertical Seismic Profiling (VSP) data are expected to give formation images of greater detail and resolution, compared to surface-seismic data. A receiver close to the target will record the wave field incident on the target, and - a little time later - the wave field scattered off the target. Measuring both the source and scattered fields close to the target should reduce wave-field ambiguities, as well as more independence from detailed knowledge of the formation between the source and the receivers. However, the spatial extent of formation image from VSP data is much smaller than from comparable surface-seismic data. To increase the image aperture, it is desirable to combine receivers that are close to the object with receivers that are further away. Adding the requirement from general wave-field measurements that one should have at-least two measurements per wavelength of the highest useable frequency of acoustic energy (for compressional waves, this typically corresponds to a wave length of about 30 m or 100 ft), one ends up wanting to deploy a rather large number of receivers. With the deepest receiver at a depth of, e.g., 5100 m, instrumenting the well to the surface would require 340 three-component (3C) receivers at 15 m spacing.

A typical recording system used for acquiring VSP data has the capacity of around 120 individual channels. Using these channels three at the time (for 3C recording), one would be limited to 40 levels. A large-scale VSP data set may require around 30000 source firings. Using a shot-point interval of 50 m, the total sailing length of the source vessel is around 810 Nautical miles. If the source vessel can operate at 5 knots, this typical survey would take a full week of un-interrupted operations to complete, while the source vessel fires one shot every 20 s. Doing this survey with 40-level 3C receiver array would require nine settings of this array. If each of these settings is associated with one week of un-interrupted data acquisition the cost in unproductive rig time for doing the survey would be 31 million USD, at rig rates of around 0.5 million USD/day. Taking a more realistic operational efficiency into consideration, this cost, which already is very high, becomes absolutely prohibitive.

As the information from a carefully processed large-scale 3D VSP data set could be used to significantly increase reservoir productivity and enhance the long-term recovery of hydrocarbons, and that such information also could be important for better placement of development wells and injectors, the operator would have to compromise between the desired image aperture, and the cost. On the other hand, acquiring the data with a hybrid system combining 3C sensors for imaging dipping structures near the bottom, with near-continuous Distributed Acoustic Sensing (DAS) to the surface, would allow the complete survey to be done in one single tool setting, and the full survey discussed above could be completed at less than 20% of the rig-time cost.

We will look at the characteristics of the DAS data acquired as a part of a recent 3D VSP survey using a hybrid receiver system (Kjos, 2013), and consider how the DAS data should be processed for optimal results. Considering that the noise characteristics, tool coupling, and sampling density are very different, we will also discuss how information obtained from DAS data and 3C-geophone data could best be combined.

## DAS Data

Figure 1 shows raw DAS shot files selected at 500 m interval along a walk-away line. The "vibration noise" is clearly visible as horizontal lines. Figure 1 also shows estimates of the vibration modes, and the DAS data after removing the vibration noise. In all three figures are included DAS receivers up to the platform floor.

The shallowest traces are significantly contaminated by noise related to bad formation coupling, sitting as they are within un-cemented multiple casing that is free to move, and apparently easily excited, along the direction that the DAS sensors are sensitive. These shallow traces have been removed from the traces used for formation imaging. This problem is also seen in the 3C Zero-offset VSP data collected over the entire well track at the end of the survey.

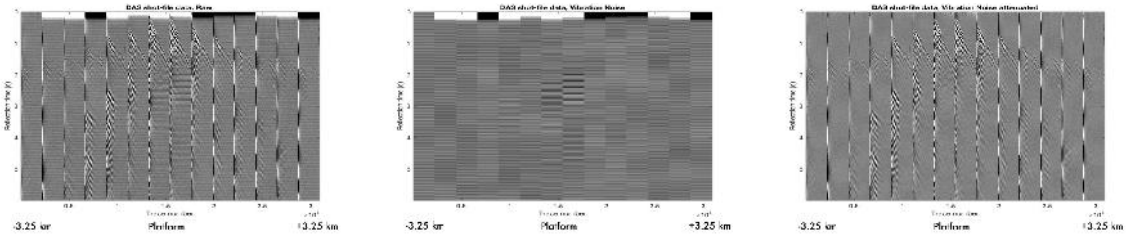


***Figure 1*** *DAS shot files selected at 500 m interval along a walk-away line. On the left, the raw data; in the middle, estimation of the vibration noise; on the right, the data with the vibration noise removed.*

Figure 2 shows DAS shot files selected at 1 km interval along a walk-away line, after removing the "vibration noise". These shot files are, in addition to "singular-spike" noise, dominated by a periodic oscillations with a period of around 0.12s, dying out after between 6 and 8 oscillations. The source used for the survey was design for maximum power and maximum azimuthal radiation symmetry. Assuming, like what is commonly seen with modern airgun sources, that the source signature is repeatable from shot to shot, we have used the shots closest to the rig to estimate the source signature, assuming that the variations seen for these few shots is representative for the survey. The figure shows the results of applying the semblance-weighted deconvolution (Haldorsen et al., 1994) to these data, nicely collapsing the air-bubble oscillation to a band-limited spike. The amplitude spectrum of this process spike shows significant energy between 5 and 40 Hz. One can notice that the singular spikes that was not attenuated prior to this application, have been significant reduced. As these spikes have different frequency characteristics from the airgun source used, these spikes will be minimized by the process, as this is the secondary objective of the semblance-weighted deconvolution process.

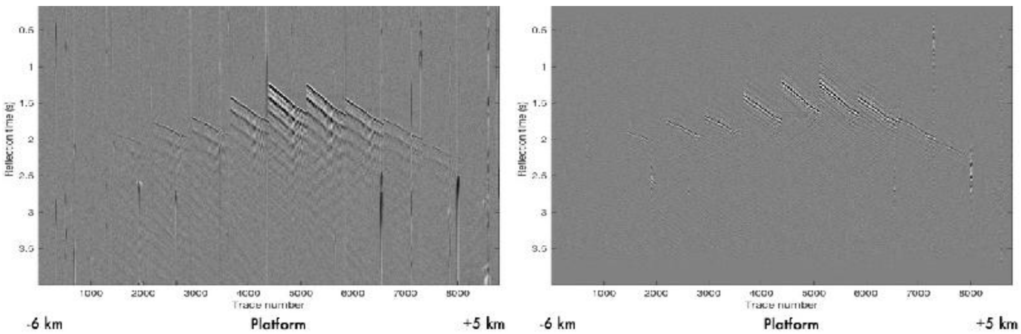


***Figure 2*** *DAS shot files selected at 1000 m interval along a walk-away line, after removing the "vibration noise". The DAS shot files shown on the left, after semblance-weighted deconvolution. These data have had no explicit filter applied to attenuate the "singular-spike" noise.*

## Conclusions: Lessons Learned

In general, the DAS recordings are noisier than geophone recordings. However, with a much denser spatial sampling than 3C geophones, migration stacking will reduce the level of noise by at-least a factor of 2.7 ($= \sqrt{7.5} = \sqrt{15\ m/2\ m}$). We also saw that deployed inside multiple-layers of un-cemented casing, neither geophones nor DAS sensors give data that suitable for VSP imaging. There appears to be a clear correlation between well inclination and quality of the DAS data. As the increases from to more than $1^\circ$ the DAS measurement shows significantly improved coherency and consistency.

## References

Haldorsen, J., D. Miller, J. Walsh, 1994, Multichannel Wiener Deconvolution of Vertical Seismic Profiles: Geophysics, 59, 10, pp. 1500-1511.

Kjos, T., 2013, Fiberoptisk og elektrisk seismikksensorkabel for tilegnelse og overføring av informasjon om seismiske hendelser registrert av flere multikomponentgeofoner i et undergrunnsreservoar: Norwegian Patent 335878.