Progress in DAS Seismic Methods

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Summary

In late 2012, we acquired a 3D Distributed Acoustic Sensing (DAS) VSP simultaneously in two injector wells in a deepwater field. We utilized seismic shots from a concurrent OBN campaign and pre-existing fiber optic cables (installed on tubing for unrelated purposes). One of the wells was mildly deviated, while the other had a complicated deviated trajectory. We obtained DAS VSP data with clear signals. The raw gathers show not only down-going P, but also PP and PS reflections, and down-going PS conversions. We also observed a surprising azimuthal phase variation in the deviated well, and some noises that underscore the importance of proper fiber connections. We conclude that 3D DAS VSP can be acquired safely and successfully in multiple deepwater wells where fiber optic cable has been installed, including wells inaccessible to geophones.
The presentation will start with a brief description of DAS concepts, followed by a description of the Mars experiment.

Introduction

3D VSP can be helpful in de-risking field developments in deepwater where surface seismic is challenged by a complex and anisotropic overburden. However, a conventional 3D VSP in the deepwater environment can be prohibitively expensive, mainly due to the required rig time. Also, placing geophones in a well carries a risk of the tools getting stuck and is often not possible in wells completed with tubing and/or complex geometries.

These objections don't necessarily apply for VSP-s acquired with Distributed Acoustic Sensing (DAS) (Mateeva *et al.*, 2012). With DAS, once a fiber-optic (FO) cable is permanently installed in a well during its completion, no subsequent well intervention or rig time is needed to acquire a VSP, making operations easier and motivating more frequent use of VSP surveys. We have demonstrated these assertions with a 3D VSP test in two wells in a deepwater field, with seismic shots provided by a synergistic acquisition of node data.

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Method

While an OBN campaign was underway over the field in late 2012, we listened to the shots to acquire the DAS VSP. We connected Optasense Interrogation Units (IU) to the surface ends of optical fibers in each of two injector wells. The fiber-optic cables in those wells were originally installed for pressure and temperature monitoring and RTCI, but they contained spare fibers suitable for DAS acquisition. Strapped on tubing, the cables covered nearly the entire length of the wells. Within the riser, the cables also traversed the entire water column on their way to the platform. Water injection was off during the shooting campaign, providing a quiet borehole environment for the DAS test.
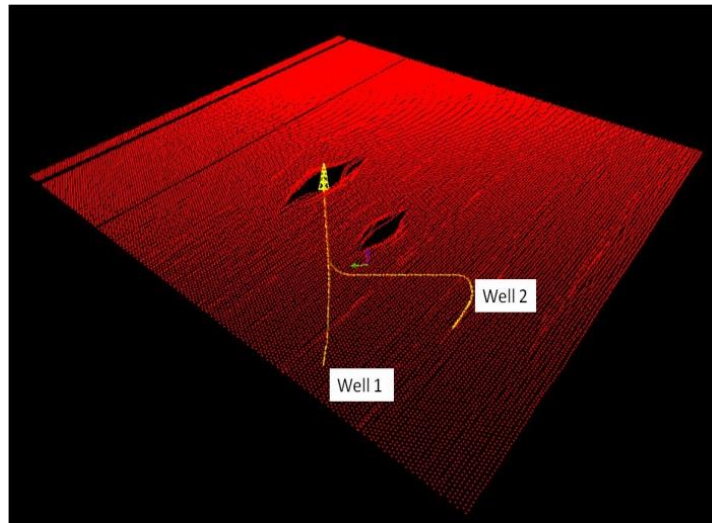

Figure 1: Acquisition Geometry: shots (red) on a 50m x 50m staggered grid over 13 km x 9 km area; DAS receivers (yellow) covered about 5.5 km MD in each well.

To minimize interference with the OBN campaign, we chose to record the DAS VSP data continuously and then extract shot records based on shot times. As an added benefit, the continuous recording provided a representative noise sample that should be useful in setting expectations for future DAS VSPs**.** Alternatively, we could have recorded the DAS data shot by shot in "triggered mode" by putting the DAS system directly in communication with the source vessel.

The DAS VSP acquisition geometry is shown in Figure 1. Having more than 700 channels at 8 m spacing on each fiber, and ~50,000 shots over 117 km^2 (13 km x 9 km) we collected some 70 million VSP traces. The shooting took six weeks in 2012. This size of a VSP would have been prohibitively expensive with geophones – it would have cost tens of millions of USD in rig time alone to cover a single tool setting of, typically, 80 geophone levels. Moreover, the completion of the two deviated injectors did not even allow for deployment of conventional geophones. In this case, DAS was the only practical option.

Examples

The data acquired in both wells proved useful, and the data quality in Well 1 is outstanding. The ambient noise level in the shallowest portion of the well is high, presumably due to the multiple casing strings there and/or acoustic coupling to the rig. Once we are below that multi-cased interval, we can clearly see not only first arrivals, but also surface multiples, PP reflections, and PS conversions on the raw VSP shot gathers before any enhancements (Figure 2). A few dim channels appear (highlighted in Figure 3c) that correspond to the cable passing through a complex completion.
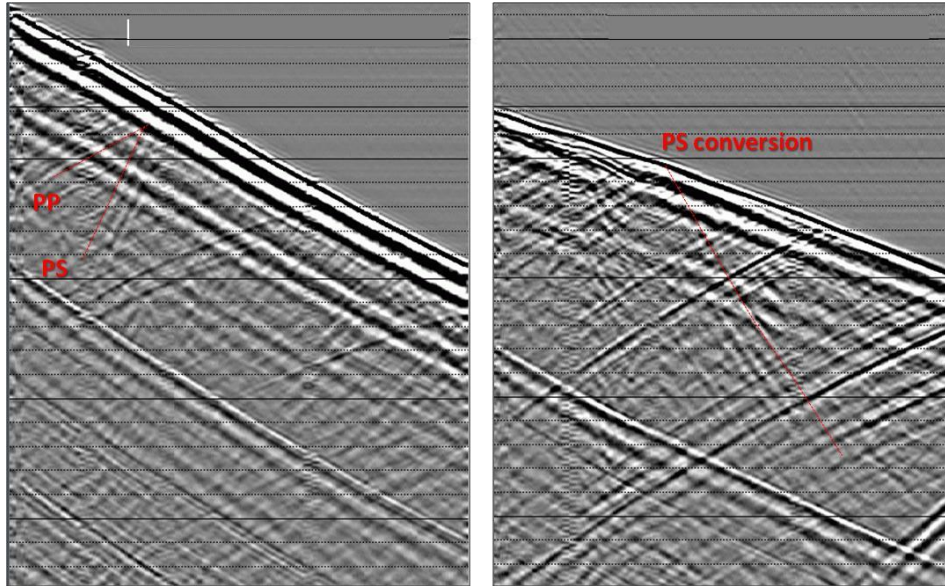

Figure 2: Typical shot gathers from Well 1 (after AVC; in quiet part of the well). The first arrival is very clear, but also PP and PS reflections are visible throughout - some are marked on the left. PS down-going conversions are visible, too (marked on the right). The airgun bubble and surface-related multiples with period ~1s are prominent, as expected.

The data in Well 2 are of lower quality than in Well 1 (Figure 3). The first arrival is still quite clear, but the later section exhibits some systematic noises - coherent in the common receiver domain, incoherent in the common shot domain. We attribute them either to suboptimal fiber splices or casing ringing (discussed in the next section). We may be able to filter the data in Well 2 to see reflections better, but, nevertheless, those noises are unwanted and may illustrate the importance of proper fiber installation.

Another peculiar feature in Well 2 is that the first arrival wavelet exhibits azimuthal phase variation (Figure 4), even for very small offsets (<1/10 receiver depth). The variation is smooth and systematic, and most noticeable in the near-horizontal portion of the well. One explanation of this variation could be that the source array had an azimuthally-dependent signature. However, no such dependence is apparent on the OBN hydrophones. Alternatively, the variation could be due to directionality in the DAS measurements. However, the type of directionality that would be required to explain the data contradicts our previous measurements and current theoretical understanding of how DAS works. Therefore, we are looking for further alternatives, including the possibility of optical distortions related to the suboptimal fiber installation in Well 2.
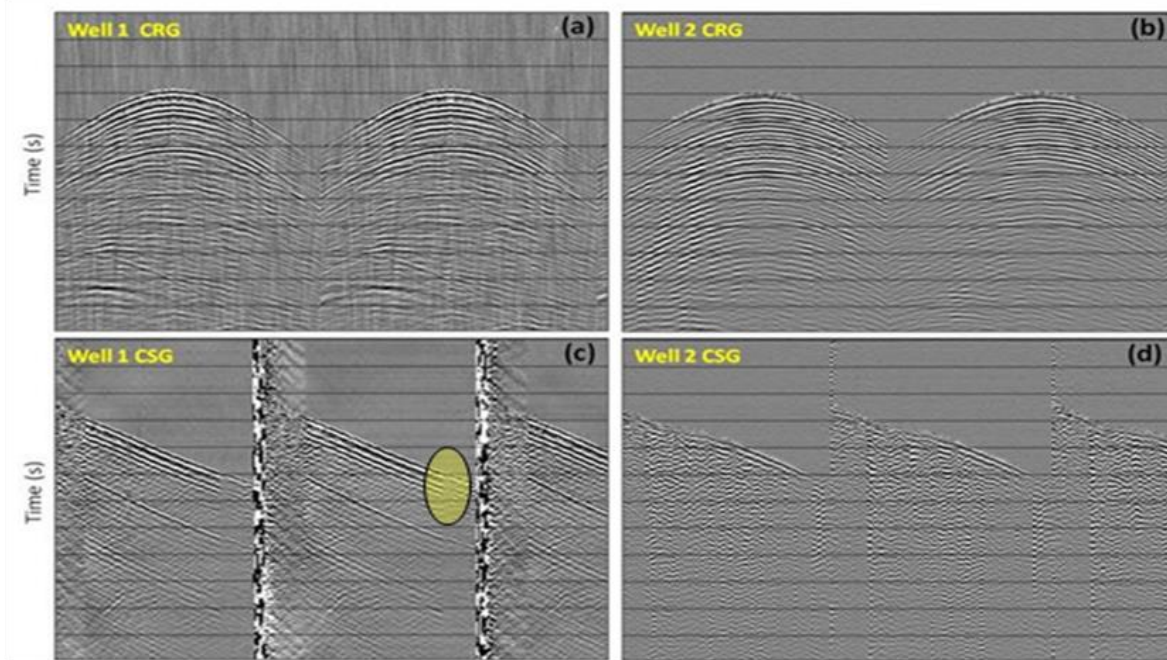
Figure 3: Comparison of raw data in wells Well 1(left) and Well 2 (right). Top: Common Receiver Gathers. Bottom: Common Shot Gathers. Poor data due to a complex completion is highlighted in 3c).
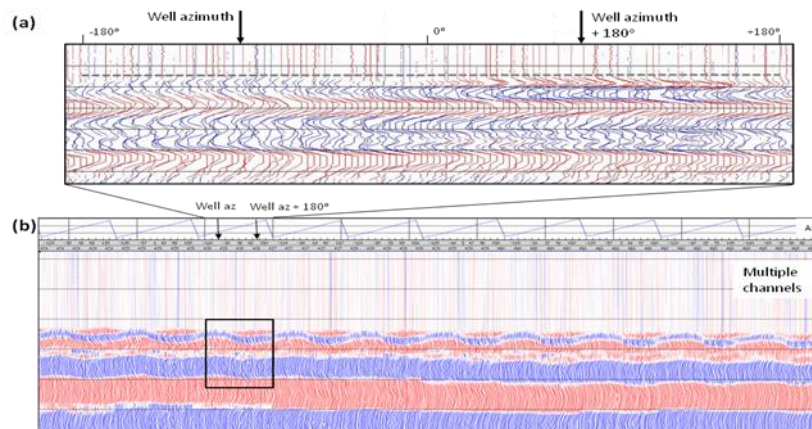

Figure 4: Small-offset shots directly above receiver location in the sub-horizontal section of Well 2. Shots sorted on azimuth, 360° range. NMO has been applied to correct for offset variations (<300m). Top: Single receiver – notice the phase change of the first arrival with azimuth. The phase extrema seem to align with the well azimuth. Bottom: same as top but for many receivers – notice the systematic nature of the phase variation.

On the Importance of Proper Fiber Installation

To measure seismic signals, DAS uses the light of laser pulses back-scattered by micro-heterogeneities in the fiber. It is important that a laser pulse exits the fiber after having traveled to its end, so that it does not interfere with later pulses. A properly installed fiber has low or no optical reflection from its end, or any other point. However, end-reflections are not uncommon in practice and can be strong relative to backscatter. They can damage the DAS IU. To protect the equipment, the IU has a built-in shutter that is effective as long as there is only one reflective point along the fiber. In complex completions, however, there may be multiple

splicing points along the fiber which, if not properly done, can be reflective. Two reflective points would trap light in the fiber, interfering with the quality of DAS measurements.

When we first tested the fiber in Well 2 with standard OTDR (Optical Time-Domain Reflectometry), we found three significant reflective points – at its bottom end, at a wellhead splice (near the platform) and at a contaminated connector that would be plugged directly into the IU box. These deficiencies were not corrected, leading to spurious, multiple reflections in the fiber and consequent seismic data degradation, perhaps related to the noise observed in Figure 3. Even if the contaminated connector was repaired, the wellhead splice would still have significant optical reflections.

The Well 2 example underscores the importance of high-quality initial installation of fibers in deepwater. In contrast, the fiber in Well 1 looked clear on OTDR and produced excellent seismic data.

Conclusions

We proved the feasibility of DAS in deepwater with a 3D VSP in an operating field. The acquisition was successfully performed in a safe manner simultaneously into two wells – deviated injectors – that were inaccessible to geophones, using fibers that were installed previously for other purposes.

The data from this particular acquisition will help position a new well. Furthermore, these data demonstrate DAS as a key enabler for 3D and 4D VSP acquisition in deepwater. Cost-efficient, safe, on-demand VSP can have a tremendous business impact in deepwater fields undergoing IOR/EOR monitoring under complex overburden.

Acknowledgements

References

Mateeva, A., J. Mestayer, B. Cox, D. Kiyashchenko, P. Wills, J. Lopez, S. Grandi, K. Hornman, P. Lumens, A. Franzen, D. Hill, and J. Roy, Advances in Distributed Acoustic Sensing (DAS) for VSP, SEG Technical Program Expanded Abstracts 2012.