Optimizing DAS VSP Value through FWI Imaging

Introduction

3D Vertical Seismic Profile (VSP) surveys using three-component geophones have a longstanding track record of delivering superior image quality around the borehole in comparison to the 3D surface seismic method. This type of survey has proven valuable in enhancing the interpretation of surface seismic data, particularly in areas where the surface seismic resolution is limited (Zhan et al., 2017). Nonetheless, the cost of 3D VSP surveys tends to be high, primarily due to the need for well intervention during acquisition. The resulting VSP images have limited coverage owing to the constrained number of geophones allowed in the borehole.

The utilization of Distributed Acoustic Sensing (DAS) technology, which uses fiber-optic cables deployed in wells to capture VSP data, has significant economic advantages for 3D VSP acquisition. This innovative technology also presents a cost-effective means for 4D seismic monitoring of reservoirs and CO2 plumes (Kiyashchenko et al., 2020). Additionally, the complete sampling of the entire well through fiber channels significantly enhances the extent of illuminated imaging areas when compared to geophone-based 3D VSP analogs. However, despite its value, the processing and imaging of DAS VSP data faces some challenges, such as high noise levels as a result of active injection/production, reduced angular coverage, and prolonged turnaround times.

In recent years, imaging with FWI (Full Waveform Inversion) has produced high-resolution images for various geological environments employing OBN (Ocean Bottom Node) and surface seismic data (e.g., Kalinicheva et al., 2020; Huang et al., 2021; Wang et al., 2021). This method combines simultaneous model building and high-frequency least-squares imaging to produce high-resolution seismic images directly from the inversion. By eliminating the need for time-consuming data conditioning steps in conventional seismic processing, imaging with FWI streamlines the overall imaging process.

In this paper, we have adapted an FWI Imaging workflow to image 3D DAS VSP data. By doing so, we can directly generate high-resolution 3D VSP images from the inversion of field DAS VSP data. The workflow uses minimally pre-processed DAS VSP data and significantly reduces both the degree of user intervention and the turnaround time typical of conventional DAS VSP imaging. Integration of free-surface multiples into the FWI Imaging workflow introduces additional data constraints and extends lateral illumination, thereby improving the resolution of FWI-derived DAS VSP images. We demonstrate this workflow on a 3D field data set recorded during a period of active water injection from a deep-water Gulf of Mexico field.

DAS VSP FWI Imaging Workflow

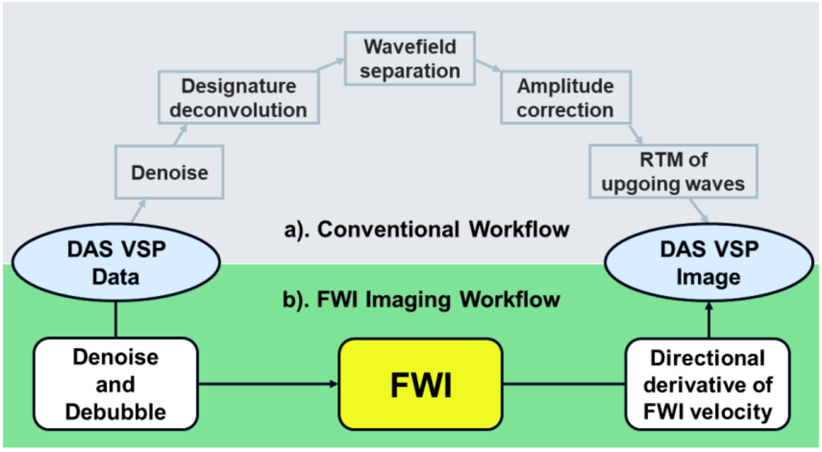

Figure 1 *Comparison of conventional workflow (upper) with the FWI Imaging workflow (lower) for imaging DAS VSP data.*

The processing of 3D DAS VSP data closely adheres to the standard sequence for processing 3D geophone VSP data. However, there are unique aspects related to DAS VSP and well trajectories that demand extra processing considerations (Wu et al., 2015). Figure 1a depicts the conventional workflow which encompasses numerous time-intensive sequential procedures. The typical processing time for 3D DAS VSP data is approximately 2-3 months, with more effort for the case of 4D processing. Figure 1b illustrates the FWI Imaging workflow contrasted to the conventional process, and it can be completed in just a few weeks.

An inherent benefit of the FWI Imaging workflow lies in its utilization of full wavefield data. In the conventional workflow, the wavefield undergoes separation into upgoing and downgoing wavefield at the borehole. The VSP image is usually derived from the upgoing wavefield. In contrast, the FWI Imaging workflow eliminates the necessity for wavefield separation. Instead, it performs a simultaneous model building and least-squares imaging using the full wavefield data which includes both upgoing primary and downgoing multiple energies.

Data pre-processing

The 3D DAS VSP field data presented in this paper were collected in 2018 from an active water injection well located in a deep-water field in the Gulf of Mexico. Figure 2a displays a map view illustrating the source (in red) and receiver (in blue) geometry. The data acquisition involved a source patch spanning 8 km x 10 km with shot spacing set at 50 m x 50 m and included a total of 25,744 shot points. To mitigate migration swings arising from uneven shot fold, shot editing was performed. Figure 2b presents the regularized shot map after discarding ~2,000 (8%) redundant shots.

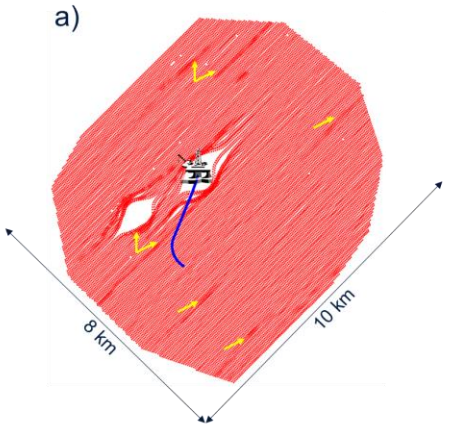

Figure 2 *Map view of 3D DAS VSP acquisition: a) prior to shot editing, and b) following shot editing. Location of redundant shots are highlighted by yellow arrows on the original shot map.*

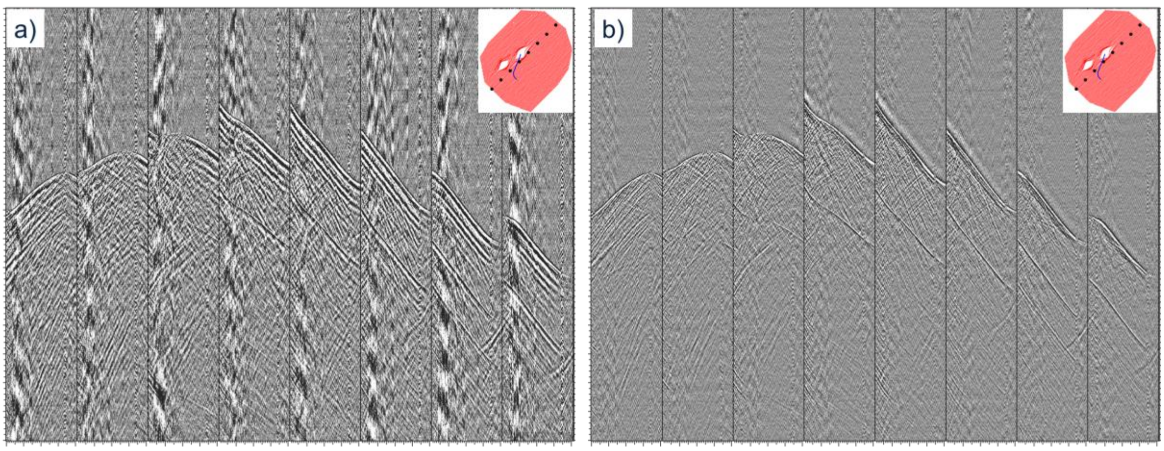

Figure 3 *Pre-processing example of injection noise and bubble noise as seen on field DAS shot gathers: a) before noise attenuation, and b) after noise attenuation.*

Figure 3a illustrates eight raw shot records extracted at various offsets along one of the sail lines. These records showcase a favourable scenario in realistic field conditions for offshore DAS VSP acquisition, featuring substantial airgun sources (2950 cubic inches), DAS recording in a flowing deviated well (specifically, an active water injector), and typical signal-to-noise ratios (attributed to injection noise) observed under operational well conditions. Figure 3b exhibits the same shot records following denoising and debubbling processes. The suppression of injection noise and bubble energy is notably evident.

Low-frequency FWI for traveltime alignment

The starting velocity model utilized (Figure 4a) was a pre-existing smoothed legacy model derived from surface seismic data. Initially, an 8 Hz first-arrival FWI was executed as a starting point to update the background model, specifically aimed at aligning the first-arrival traveltimes. The FWI tomogram resulting from 20 iterations is shown in Figure 4b. To validate the FWI model, traveltime misfits between the field first-arrivals and modelled first-arrivals before and after FWI were computed and compared in Figures 4c and 4d. The visible minimization of the first-arrival traveltime misfit shows the accuracy and effectiveness of the FWI process.

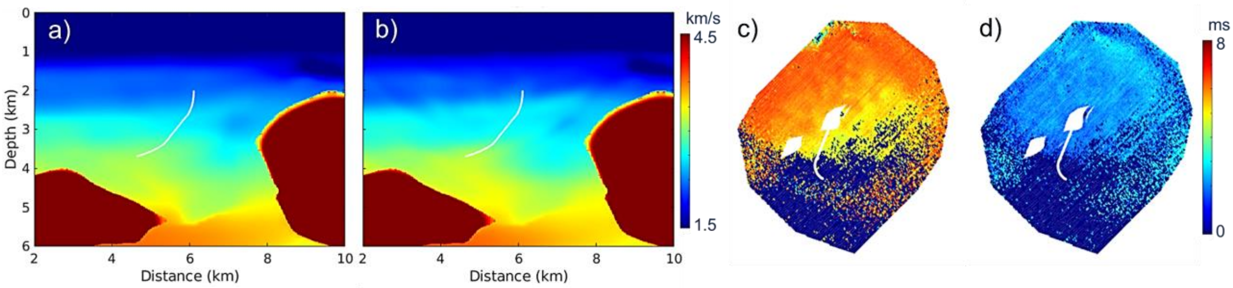

Figure 4 *Results and QC of the 8 Hz first-arrival FWI: inline section of the velocity model before (a) and after (b) FWI; misfit plot for first-arrival traveltimes corresponding to a receiver at a depth of 3 km before (c) and after (d) FWI.*

High-frequency FWI for high-resolution imaging

After aligning the first-arrival traveltimes with an updated background model, we advanced to a higher-frequency FWI aimed at achieving high-resolution imaging. This high-frequency FWI utilizes the full wavefield data, including transmission and reflection waves, primaries, and multiples, enabling a simultaneous inversion for both the velocity and reflectivity models.

Figure 5a presents the outcome of FWI Imaging which is the directional derivative of the final 35 Hz FWI velocity. The enhanced vertical and lateral resolution are clear when comparing the FWI image to the 35 Hz RTM image of upgoing waves, illustrated in Figure 5b. Notably, the image amplitude is more balanced, and migration artifacts along and below the wellbore are suppressed through the least-squares data fitting process. In addition to the improvements in resolution and imaging, the benefit of extra illumination from free-surface multiples is also observed, contributing to the extension of the image over a broader area.

Conclusions

An FWI Imaging workflow tailored for maximizing imaging resolution of DAS VSP data is showcased with its application on field data. The results presented show that FWI Imaging not only enhances resolution and image quality but also expands the illumination by inverting and imaging the full wavefield data. Furthermore, compared to conventional DAS VSP processing, FWI Imaging potentially reduces processing time from months to weeks.

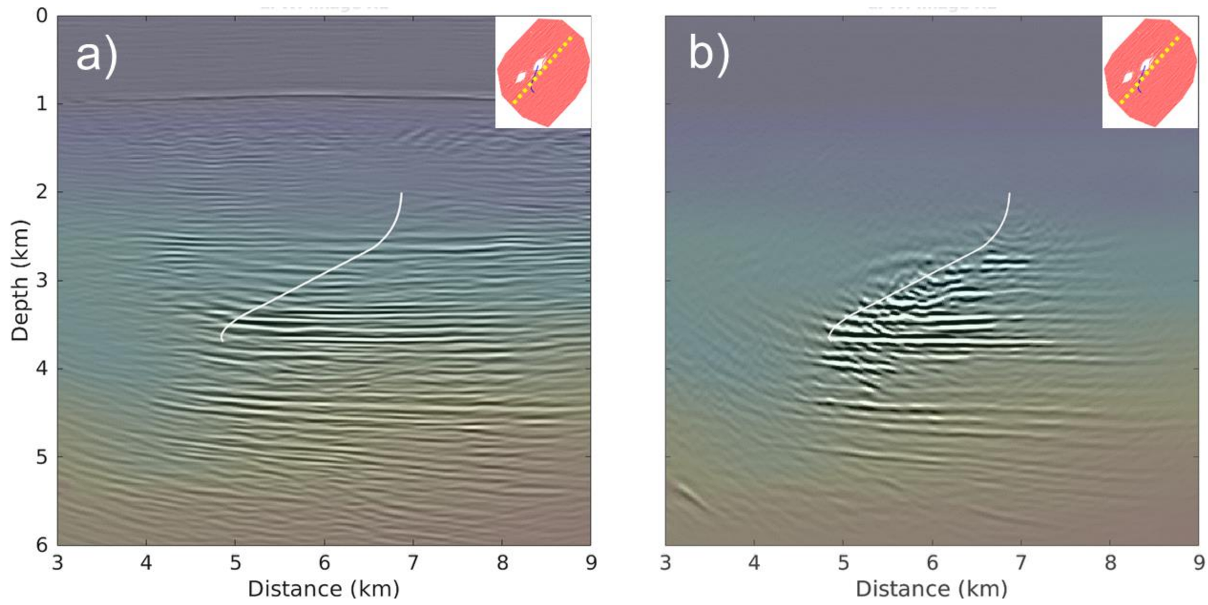

Figure 5 *Section view and comparison between the 35 Hz FWI image (a) and the 35 Hz RTM image (b).*

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